AR14

Annual Report 1974

Hudson's Bay Oil and Gas Company Limited

HUDSON'S BAY OIL AND GAS COMPANY LIMITED
1974 ANNUAL REPORT

CONTENTS

ABOUT THE COMPANY

Hudson's Bay Oil and Gas Company Limited has been actively engaged for many years in acquiring petroleum and natural gas rights in Canada and in the exploration for and development of hydrocarbons. The Company today is one of the major producers of crude oil, natural gas liquids and natural gas in Canada, and is also a leading producer of sulphur. In addition, it is involved in the transportation, purchase and sale of crude oil, natural gas liquids and sulphur. The Company operates a metallic minerals exploration program in Canada and, in the past two years, has expanded its petroleum exploration activity to areas outside Canada.

ANNUAL MEETING OF SHAREHOLDERS

The Annual Meeting of Shareholders will be held at the Head Office of the Company at 320 - 7th Avenue, S.W., Calgary, Alberta, Canada, on Tuesday, April 22, 1975 at 11:30 a.m.

ADDITIONAL INFORMATION

Copies of the Annual Report on Form 10-K filed with the Securities and Exchange Commission of the United States are available free of charge by writing to the Corporate Secretary of the Company.

A PERSPECTIVE ON THE CURRENT ENVIRONMENT FOR PETROLEUM EXPLORATION AND PRODUCTION IN CANADA

Over the past year there have been an unprecedented number of major changes in the broad array of domestic and international factors that significantly influenced the operating and investment climate for the Canadian petroleum industry. Substantial increases in selling prices combined with continuing strong demand for crude oil and natural gas resulted in most members of the industry reporting record gains in earnings. At the same time, however, the market price for the shares of these companies declined very abruptly and many of them restricted or reduced their level of spending for finding and developing new reserves. How can these apparent contradictions be reconciled? A complete analysis involves many factors but the essential ingredient is uncertainty — and the resulting lack of confidence in the industry's opportunity and ability to earn a return on invested capital commensurate with the risks inherent in its operations.

One of the principal factors contributing to this uncertainty has been the frequency of substantial and uncoordinated changes in royalty and tax regulations by the Federal and Provincial Governments. These changes have greatly increased government's share of the revenues derived from petroleum production. Another disturbing factor has been the expanding Government intervention into the market distribution and pricing of crude oil and natural gas. These traditionally have been functions of the private sector and have been permitted to respond to changes in market conditions.

The uncertainty has also been aggravated by the rapidly escalating costs of finding and developing new reserves, particularly in the frontier areas and in the oil sands. The impact of all these factors is cumulative and is further compounded by the long lead times involved in petroleum exploration and development and the resulting need to base today's investment decisions on an assessment of the economic and political environment that will prevail in future years.

In these circumstances what operating and investment policies should the petroleum industry adopt? In our view it has an obligation to use its skills and resources in the best interests of its shareholders and the nation and therefore should direct its efforts toward achieving the very substantial benefits that accrue from maintenance of Canada's enviable position of self-sufficiency in energy supplies. This clearly warrants continuation of active exploration in the western provinces — which still hold promise of important reserve additions — expanded exploration in the more prospective frontier regions, and accelerated development of production from the oil sands. These programs, however, will involve large high risk expenditures of which a major portion can only be financed from internally generated funds. If the Federal and Provincial Governments continue to take too large a share of the industry's revenues there will be insufficient funds generated from internal sources to carry out the necessary programs.

While these conclusions indicate a vital need for improvement in the petroleum investment climate, the industry will not completely defer all new investment. Most companies have a broad range of investment opportunities and the more attractive projects should prove economic even under current tax and royalty provisions.

Hudson's Bay Oil and Gas Company expects to maintain a substantial level of exploration and development expenditures. We will continue to drill exploratory wells at our most prospective locations and will make selective acquisitions of acreage to enhance our land position in the most favourable areas. Development programs to maintain production revenues or to improve protection of the environment will proceed. Other exploration and development activities required to maintain our competitive position will be continued in anticipation of improvement in the economic and political environment. In addition, we will be actively seeking investment opportunities in other energy related fields that would provide diversification in revenue sources.

FINANCIAL AND OPERATING HIGHLIGHTS

	1974	1973	Increase (Decrease) Per Cent
FINANCIAL			
Total Revenues — (Before deducting royalties)	$258,612,000	$165,109,000	56.6
Net Earnings	$ 58,352,000	$ 39,370,000	48.2
Per Common Share	$ 3.07	$ 2.07	48.3
Funds Generated from Operations	$ 91,502,000	$ 74,623,000	22.6
Per Common Share	$ 4.83	$ 3.93	22.9
Dividends Declared	$ 18,168,000	$ 14,384,000	26.3
Per Preferred Share	$ 2.50	$ 2.50	—
Per Common Share	$ 0.95	$ 0.75	26.7
Capital Expenditures	$ 45,685,000	$ 42,959,000	6.3
Exploration Expense	$ 13,735,000	$ 11,346,000	21.1
Working Capital (At year end)	$ 55,448,000	$ 34,023,000	63.0
OPERATING			
(All production, sales and reserves volumes are before deducting royalties — see footnote)			
Crude Oil Production — (Barrels per day)	62,295	67,410	(7.6)
Natural Gas Liquids Production — (Barrels per day)	26,452	26,870	(1.6)
Natural Gas Sales — (Millions of cubic feet per day)	436.6	434.7	0.4
Sulphur Sales — (Long tons per day)	1,152	1,195	(3.6)
Pipe Line Throughput (Barrels per day)	111,969	114,524	(2.2)
Oil and Gas Rights (Net acres at year end)	22,254,000	24,664,000	(9.8)
Proved and Probable Reserves (At year end)			
Crude Oil (Barrels)	270,276,000	273,277,000	(1.1)
Natural Gas Liquids (Barrels)	105,469,000	116,207,000	(9.2)
Natural Gas (Millions of cubic feet)	3,660,000	3,766,000	(2.8)
Sulphur (Long tons)	9,933,000	10,778,000	(7.8)

NOTE:

Throughout this report the Company's hydrocarbon production, sales and reserves volumes are reported on the basis of its ownership interests before deducting royalties. This procedure has been adopted to facilitate year to year comparisons of operating results which otherwise would be obscured by the increasing frequency of changes in basic royalty rates and the introduction of supplementary royalty rates which vary with sales prices.

Hudson's Bay Oil and Gas Company Limited recorded substantial increases in revenues, funds generated and net earnings in 1974 despite sharply higher royalty rates, income tax changes and large inflationary cost increases. Part of these gains, however, were derived from a net reduction in hydrocarbon reserves and thus overstate the real results of the year's operations as the revenues and earnings reported from this liquidation of assets will be offset by higher replacement costs.

FINANCIAL AND OPERATING RESULTS

Net earnings for 1974 were $58.4 million or $3.07 per common share, an increase of 48% over the $39.4 million or $2.07 per common share earned in 1973. Funds generated from operations totalled $91.5 million or $4.83 per common share, a 23% gain over the prior year. The Federal Budget which was presented on November 18, 1974, contained income tax changes that were retroactive to May 7 and therefore affected the earnings previously reported by the Company in its June 30 and September 30 interim reports to shareholders. The impact of these changes on quarterly earnings is shown on page 23 of this report.

There is growing concern about the distorting effect of high rates of inflation on the reported earnings shown by conventional accounting practices and the resulting inequitable application of income taxes. Various accounting concepts and procedures have been proposed to overcome this problem, but no general agreement has been reached as to the most appropriate method. In December, 1974 the Canadian Institute of Chartered Accountants issued guidelines on "Accounting for the Effects of Changes in The Purchasing Power of Money." Although these guidelines differ in some important respects from the procedures recommended by other professional accounting bodies, we have used them in the Supplementary Financial Information section to recalculate the Company's 1974 results. As explained in that section, the restated net earnings for the year would be moderately higher but the indicated return on the restated shareholders' equity would be substantially reduced. The C.I.C.A. guidelines may require modification but their issue was an important step toward initiating the broad public discussion and analysis that is essential to the development of improved accounting methods for dealing with the problems caused by inflation.

Production volumes of crude oil and natural gas liquids — before deducting royalties — were down almost 6% in 1974 due to a combination of declining productivity in a number of fields and reduced market demand resulting in part from the Federal Government's export tax of $5.20 per barrel. Natural gas sales volumes were essentially unchanged from the prior year with a gain of less than 1%. There was a substantial improvement, however, in the sales price obtained for each of these products. The most significant gain was a $2.70 per barrel increase for crude oil and condensate effective April 1, 1974 although a major portion of this increase was offset immediately by higher royalty rates. The average sales price for natural gas also increased due to price redetermination in a number of our sales contracts. Most of these changes in gas contracts were in effect for only the latter months of the year and therefore had a limited impact on the 1974 average price. The price gains resulting from contract redeterminations were substantial, however, and reflect a trend toward ultimate recognition of the commodity value of alternate fuels as the appropriate market price for natural gas.

CAPITAL EXPENDITURES AND EXPLORATION EXPENSES

Expenditures on exploration activities and other capital investment programs totalled $59.4 million in 1974, an increase of $5.1 million or 9.4% over the prior year. The expansion of our foreign exploration activities accounted for a major part of the increase with total outlays for this purpose reaching $6.4 million compared with only $0.4 million in 1973.

The amounts spent on domestic exploration and development activities also increased but fell short of the targets we had set at the beginning of the year. The originally planned capital expenditures and exploration expenses totalled approximately $75 million for 1974 but when the Provincial and Federal Governments announced their intentions to enlarge greatly their royalty and income tax levies, we reviewed our spending plans and postponed or cancelled projects that were not essential to maintain current revenues or competitive position.

Expenditures on domestic exploratory drilling in 1974, at $8.6 million, were up $1.9 million but the number of wells in which we participated declined to 78 compared with 127 in 1973. This drilling program resulted in 31 gas discoveries

or extensions, principally in west-central Alberta, and nine oil discoveries or extensions. Although most of these discoveries and extensions have only limited potential, a number of the new finds provide prospects of moderately important additions to our proven oil and gas reserves. After taking into account the large volume of production during the year, however, the net result was another decline in the Company's remaining reserves.

The Company's development drilling activity was off sharply from the 1973 level which included large programs for development of heavy oil reserves in Saskatchewan and shallow gas reserves in south-eastern Alberta. Expenditures were down 40% to $6.4 million and the number of completions dropped to 79.1 net wells compared with 131.4 net wells in 1973.

Negotiations have been completed to increase the Company's joint venture participation in the Alberta Oil Sands Project from 14.6% to 18.8% effective November 1, 1974. The acquisition of this additional interest from a participant who is withdrawing from the project is subject to review by the Foreign Investment Review Agency who currently are considering our application. The Energy Resources Conservation Board has recently recommended that the Alberta Government approve the AOP group's application for a permit to develop a large scale mining and processing project to produce 122,500 barrels per day of synthetic crude oil from the Athabasca oil sands. The rapid escalation in construction costs being reported by the Syncrude group who have a similar oil sands project currently underway, and the uncertainty with respect to future market prices, royalty and taxation policies, raise serious questions on the timing and economic viability of the AOP proposal.

PLANS FOR 1975

The increased emphasis on exploration outside of Canada will be maintained in 1975 and we will be aggressively pursuing energy related opportunities in Canada to broaden the scope of the Company's operations. Unless there is a significant improvement in the investment climate, spending on domestic petroleum exploration and development will be held to somewhat lower levels than in 1974. We currently plan to maintain our exploration spending at a reasonably high level in Alberta but probably will reduce expenditures in some other areas of Canada. Development expenditures are projected to increase in 1975 due principally to larger outlays on gas plant construction.

INDUSTRY REVIEW AND OUTLOOK

Canadian production of crude oil and condensate declined by 7% to an average of 1.8 million barrels per day in 1974 as a result of a sharp drop in exports to the United States. These export shipments averaged 900,000 barrels per day, a reduction of 238,000 barrels per day from the average of 1973. Reflecting growing concern over the longer term adequacy of domestic supplies the Federal Government has further reduced the permitted volume of exports to 800,000 barrels per day beginning January 1, 1975 and, subject to agreement by the producing provinces, proposes another reduction to 650,000 barrels per day on July 1. These actions are part of a plan to phase out all export shipments by 1983 unless Canadian productive capacity increases in the intervening period to provide some surplus over the projected domestic demands for the ensuing ten years. The reductions in exports will be partially offset by increasing domestic demand but Canadian production will be substantially restricted and some fields will be producing at less than full capacity. There is little prospect for improvement in this situation until completion of a proposed pipe line to deliver 250,000 barrels per day to the Montreal market.

The volume of Canadian natural gas produced and sold in 1974 averaged 6.5 billion cubic feet per day, an increase of 5.3%. Domestic deliveries increased 9.5% to an average of 3.7 billion cubic feet per day while exports were unchanged at an average of 2.8 billion cubic feet per day. Export shipments are expected to remain at this level for 1975 but domestic sales should rise by approximately 8%. Production of LPG (propane and butane) averaged 165,000 barrels per day in 1974, essentially the same level as in the prior year, but is expected to increase by approximately 6% in 1975. Sulphur sales averaged 13,600 long tons per day in 1974, a gain of 15% and a similar increase is anticipated in 1975.

Prices for crude oil, natural gas, natural gas liquids and sulphur are all expected to increase in 1975. Under the existing Federal Government controls, crude oil prices are scheduled to remain frozen at current levels until June 30

however the Alberta Government has indicated it will press for price increases after the winter heating season is over. Effective January 1, 1975, the Federal Government established a minimum price for natural gas exports of $1.00 per thousand cubic feet at border delivery points. Most of the domestic sales contracts are also scheduled for price redetermination in 1975 and LPG prices are expected to benefit from the increase in the value of alternate fuels. The trend established in 1974 toward higher prices for sulphur is expected to continue.

Exploration and development activity in western Canada declined during 1974 due chiefly to the unfavourable impact of royalty and tax changes and the uncertainty created by expanding government involvement in the industry's affairs. As a result there has been a large movement of drilling and geophysical crews and equipment to the United States where there is a strong demand for their services and a more attractive price and regulatory climate. The loss of this manpower and equipment will limit the Canadian industry's ability to respond quickly to any improvement that may occur in the investment and political environment. The Alberta Government has recently taken some positive steps to improve the industry's net return from production in that province and the Federal and Saskatchewan Governments have slightly moderated the excessively high levies which they had previously proposed or implemented. British Columbia has proposed a new arrangement which will modify the effect of income tax on gas operations. Further improvements will be required, however, before any substantial revival in exploration and development activity can be anticipated. Such action is urgently needed because Canada faces the prospect of a net deficiency in petroleum supplies before the potentially large additions from the oil sands and frontier areas can be brought into production in the 1980's. Failure to encourage the required exploration and development spending could cost the Canadian economy many billions of dollars in expenditures for imported crude oil to meet domestic requirements in future years.

DIRECTORS AND EMPLOYEES

The Company suffered a loss in 1974 through the deaths of two Directors, Mr. T. N. Beaupré and Mr. John G. McLean. They had served with distinction on the Board for many years and their advice and counsel will be sorely missed. The resulting vacancies on the Board were filled by Mr. George T. Richardson and Mr. J. E. Finley. Mr. Richardson is President of James Richardson & Sons, Limited and Governor of the Hudson's Bay Company. Mr. Finley is Executive Vice-President of the Western Hemisphere Petroleum Division of Continental Oil Company.

In its senior management group the Company also suffered a loss through the death of Mr. F. J. Mair, General Manager of Administrative Services. In his 24 years of employment with the Company Mr. Mair had provided valued services in a number of Senior Administrative positions. Other Senior Management changes during the year included the promotion of Mr. O. Humeniuk to the position of General Manager, Administrative Services and the promotion of Mr. F. Callaway to Manager, Special Projects Department. In addition, Mr. G. Redlich joined the Company as Manager, Business Development.

The success achieved during the year reflects the individual skill and dedication of the more than 1,100 men and women who carry out the various operating and staff functions of the Company. The Directors wish to record their appreciation of this fine effort.

Submitted on behalf of the Board of Directors
February 14, 1975, Calgary, Alberta

D C Jones

D. C. Jones
President

GENERAL

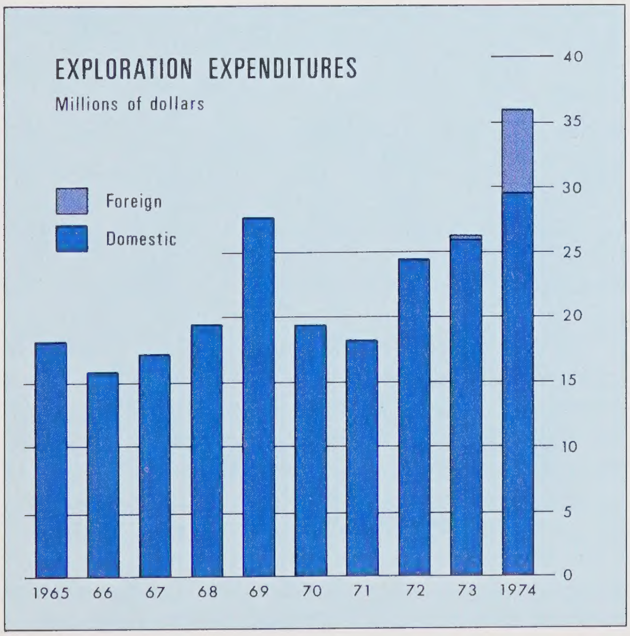
Exploration expenditures in 1974 — including capital and expense items — totalled $35.9 million, an increase of $9.7 million or 37% over 1973. The major factor contributing to the increase was the substantial expansion of foreign exploration activities as disclosed by the following comparative summary of expenditures:

	1974	1973
Petroleum Exploration		
Domestic:		
Acreage expenditures	$ 7,899,000	$ 8,091,000
Drilling expenditures	8,641,000	6,789,000
Other Expenses	12,395,000	10,214,000
	$28,935,000	$25,094,000
Foreign:		
Acreage expenditures	$ 5,067,000	$ —
Drilling expenditures	603,000	—
Other Expenses	705,000	362,000
	$ 6,375,000	$ 362,000
Minerals Exploration	635,000	770,000
Total	$35,945,000	$26,226,000

DOMESTIC PETROLEUM EXPLORATION

Domestic exploration expenditures in 1974 were directed principally toward the acquisition and evaluation of prospects in Alberta and British Columbia but modest programs also were carried out in the Mackenzie Delta, the Arctic Islands and off the East Coast.

Although the 1974 expenditures on exploratory drilling were 27% greater than in the prior year, participation in exploratory completions declined to 39.6 net wells compared with 60.1 in 1973. The divergent trend in expenditures and number of completions is attributable to a number of factors, including location and depth of the wells, inflationary cost increases, and an improved success ratio with consequent additional completion costs.



The gross number of exploratory tests in which the Company participated in 1974 also declined to a total of 78 compared with 127 in the preceding year. These totals included 40 and 47 wells respectively in which the Company participated through farmout arrangements where the entire cost was borne by others in order to earn interests in the properties. The total cost related to the 1974 farmout wells is estimated to be $8.0 million. The geographic distribution of the 1974 completions was 57 wells in Alberta, 14 in British Columbia, five in Saskatchewan, one in the Northwest Territories, and one offshore from Prince Edward Island.

EXPLORATORY WELL COMPLETIONS

	1974		1973	
	Gross	Net	Gross	Net
Oil	9	5.6	13	7.7
Gas	31	16.5	30	16.9
Dry	38	17.5	84	35.5
Total	78	39.6	127	60.1
Average Depth	5,552 feet		5,465 feet	

The 1974 exploratory drilling program resulted in 40 oil and gas discoveries or extensions. The more significant discoveries and extensions are shown in the accompanying schedule and map, and are discussed in greater detail in the following paragraphs. The other successful exploratory completions in which the Company participated are of lesser importance due to limited prospects for development of significant reserves or because the Company has only a small ownership interest.

DISCOVERIES AND EXTENSIONS IN 1974

Name of Field or Area	Discoveries and Extensions Number	Discoveries and Extensions Nature	Approximate Depth
Alberta			
Bearberry	3	Oil	8,100′
Edson	3	Gas	8,500′
Fir	1	Gas	8,900′
Jackfish	1	Gas	11,000′
Pine Creek	1	Oil	8,400′
Pinto	1	Gas	10,800′
Sundance	1	Gas	10,800′
British Columbia			
Robertson	1	Gas	4,000′

Bearberry — The Company participated in an oil discovery and two successful follow-up wells which extended the indicated reservoir to more than six miles. Two of the wells were drilled on 50% owned lease blocks containing 6,200 acres and one well was drilled on a 1,300 acre lease block which is wholly-owned. Subsequent to the discovery well, a 100% interest in an additional 1,300 lease acres in the general area was acquired at a cost of $146,000.

Edson — A jointly-owned gas discovery in December, 1973 was followed up by three successful gas wells which extended the reservoir three miles to the south and two miles to the north. The Company has a 50% interest in two of the extension wells and the other is wholly-owned.

Fir — A successful step-out well extended the Fir gas field two and one-half miles to the southeast. The well was drilled on a 21% interest lease block containing 4,800 acres.

Jackfish — A gas discovery was drilled approximately five miles southeast of the Grizzly gas field on a one-section lease block in which the interest held is 41-2/3%. Subsequently the Company and its partners added to their strong acreage position in the surrounding area through the acquisition of 1,900 lease acres for $911,000.

Pine Creek — Oil was discovered on a 41-2/3% owned lease block containing 3,800 acres. Subsequently, a 9,000 acre drilling reservation adjacent to the discovery was acquired by the Company and its partners at a cost of $312,000.

Pinto — Gas was discovered in a 50% venture 9 miles north of the Obed gas field on a 9,600 acre drilling reservation. The Company and its partners increased their extensive holdings through the purchase of a 9,800 acre drilling reservation and 900 lease acres at a total cost of $841,000.

Sundance — The Company participated in a gas discovery approximately nine miles east of the Obed gas field on a 2,400 acre lease block in which it has a 50% interest. Subsequent to the discovery an adjoining 10,200 acre drilling reservation and 1,800 lease acres were acquired by the participants at a gross cost of $2.6 million.

Robertson — A successful gas well was drilled on a wholly-owned 7,000 acre drilling reservation, approximately four miles north of the Cypress gas field. The Company has a 100% interest in 57,400 acres in the immediate area.

1974 DISCOVERIES AND EXTENSIONS

On Prince Edward Island offshore acreage, the East Point E-49 well which was suspended in November, 1970 because of unfavourable weather conditions, was re-entered and tested in October, 1974. An encouraging but non-commercial flow of gas was encountered and the well was subsequently abandoned. Under the terms of a farmout agreement, another company has an obligation to pay 25% of the re-entry costs of this well and the entire cost of additional exploration consisting of the drilling of at least one well on Prince Edward Island and a geophysical program on the farmout acreage. Upon completion of this program, the new participant will earn a 25% interest in the 9.2 million acre block and the Company's interest will be reduced from 33.3% to 25%.

ACREAGE PURCHASES

Location	Net Cost	Acreage Gross	Acreage Net	Type
Alberta				
Sundance	$1,284,000	10,200	5,100	Reservation
		1,800	900	Lease
Botha	1,207,000	18,700	18,700	Reservation
Edson	988,000	28,200	23,000	Reservation
		2,100	1,400	Lease
Whitecourt	918,000	36,100	14,800	Reservation
		7,200	3,200	Lease
Brazeau	708,000	2,600	2,600	Lease
Warrensville	499,000	11,700	11,700	Reservation
		600	600	Lease
Pinto	305,000	9,800	2,400	Reservation
		900	600	Lease
Other	187,000	56,700	42,700	Reservation and Permit
	456,000	52,300	19,600	Lease
	$6,552,000	238,900	147,300	
British Columbia	736,000	176,900	107,100	Reservation and Permit
	50,000	1,800	1,300	Lease
Saskatchewan	39,000	11,600	11,600	Lease
East Coast	447,000	372,400	372,400	Permit
Northwest Territories	75,000	30,100	3,900	Permit
Total	$7,899,000	831,700	643,600	

Reservations and permits are convertible into leases to the extent of approximately 50%.

Including the acreage additions related to discoveries and extensions already described, the Company acquired 742,000 net acres of petroleum and natural gas rights in 1974, of which 644,000 acres were purchased at a cost of $7.9 million and another 98,000 acres were obtained through filing and other types of acquisitions that did not require bonus payments. The major portion of the expenditures were incurred for acreage purchases in Alberta as shown by the accompanying table.

The acquisitions supplement large existing acreage holdings and will improve the Company's position in prospective undeveloped areas near existing oil and gas production. On the East Coast, the 372,400 permit acres will increase the Company's exposure in the Labrador shelf area where other operators have recently encountered encouraging exploratory results.

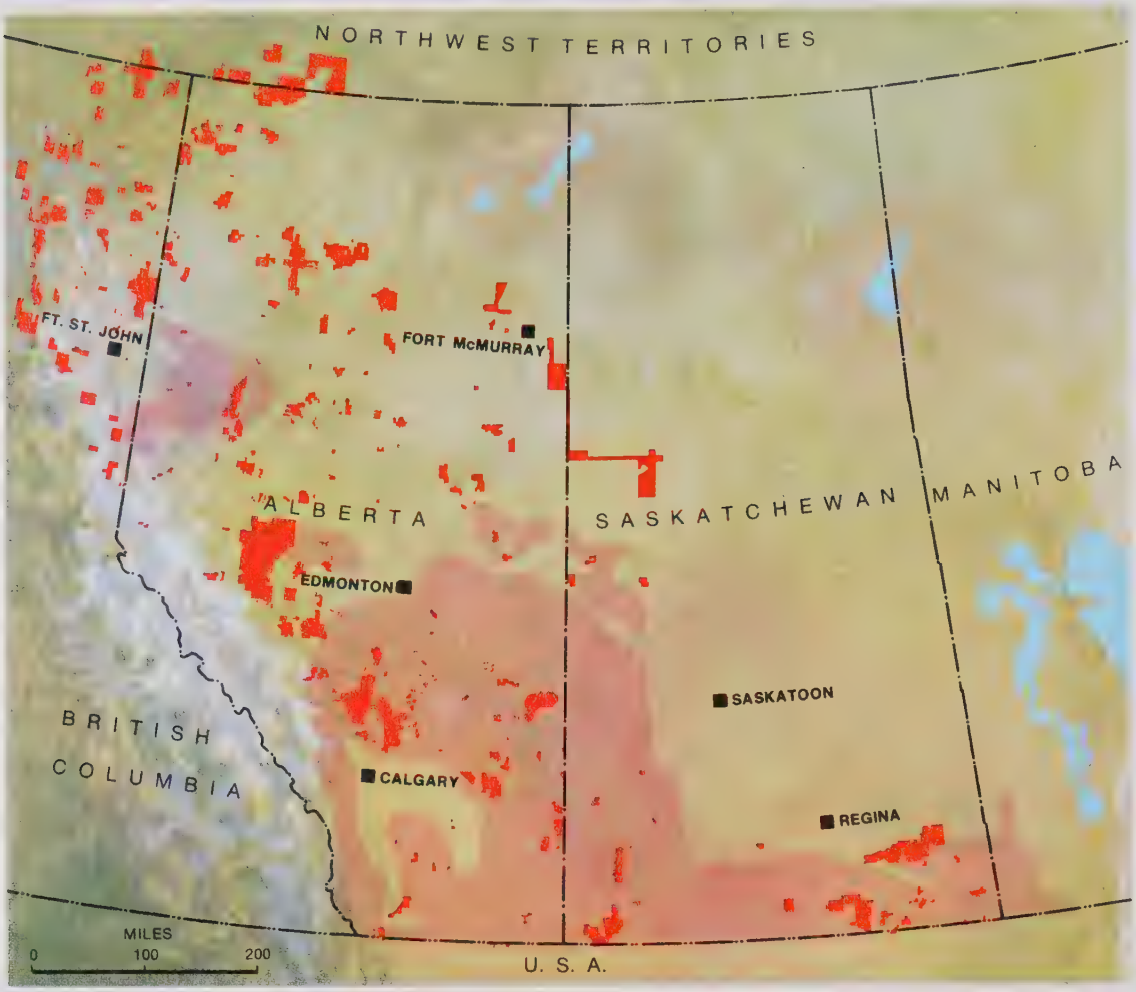
During the year interests in 3.3 million acres of petroleum and natural gas rights were surrendered or released. These included 2.8 million acres released after geological and geophysical evaluation, 415,000 acres surrendered under governmental regulations on conversion of permits and reservations to lease status and interests equivalent to 90,000 net acres assigned to other companies as consideration for drilling on Company lands. In addition 60,000 acres were transferred to the developed category.

Year end holdings of undeveloped petroleum and natural gas rights in Canada amounted to 21.5 million net acres which were acquired at a total cost of $68.1 million. Rental payments in 1974 totalled $3.0 million and mineral taxes paid to the provinces on undeveloped freehold acreage totalled $664,000.

FOREIGN EXPLORATION

The Company continued to expand its exploration activity in areas outside of Canada through the purchase of interests in the North Sea and the United States. An 11.7% interest in 12 separate blocks totalling 1.1 million acres in the Netherlands sector and 0.1 million acres in the German sector of the North Sea was purchased early in 1974 for $4.9 million. In the United States, interests were acquired in leases in California, Louisiana, Texas and Wyoming. Joint acreage applications have been filed on offshore areas of Ireland, Greenland and Indonesia and the respective government decisions are expected early in 1975. A joint application for Norwegian offshore acreage which was filed late in 1973 was unsuccessful. At year end, the Company held 139,200 net acres of un-

WESTERN CANADA



ARCTIC ISLANDS

UNDEVELOPED PETROLEUM AND NATURAL GAS RIGHTS
Gross and Net Acreage Holdings (in Thousands of Acres)
At December 31, 1974 (1)

	Crown Reservations and Permits (2)		Leaseholds		Siebens Lands (3)		Freehold Lands		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
British Columbia	1,566	916	890	540	6	6	—	—	2,462	1,462
Alberta	1,414	1,153	3,271	2,076	1,386	1,386	83	83	6,154	4,698
Saskatchewan	1,794	1,740	242	230	1,178	1,178	101	101	3,315	3,249
Manitoba	—	—	—	—	39	39	89	89	128	128
NWT (Including Arctic Islands & Baffin Offshore)	9,790	7,076	587	500	—	—	—	—	10,377	7,576
East Coast (4)	13,673	4,364	—	—	—	—	—	—	13,673	4,364
Total Canada	28,237	15,249	4,990	3,346	2,609	2,609	273	273	36,109	21,477
United States	—	—	15	5	—	—	—	—	15	5
North Sea	—	—	1,202	134	—	—	—	—	1,202	134
Total	28,237	15,249	6,207	3,485	2,609	2,609	273	273	37,326	21,616

(1) Gross acreage represents the total number of acres in which the Company has a participating interest.
Net acreage represents the Company's share of gross acreage calculated in accordance with its various ownership interests.
Net acreage holdings are subject to modification by exploration agreements whereby others may earn an interest in the Company's acreage by undertaking certain exploratory work.
(2) Convertible into leases to the extent of approximately 50%.
(3) Held under an agreement with Siebens Oil and Gas Ltd. which permits conversion to leases at any time up to December 31, 1999 without bonus payment.
(4) Offshore permits include 5,100,000 gross (1,793,000 net) acres covered by Federal but not Provincial rights and 1,822,000 gross (357,000 net) acres covered by Provincial but not Federal rights.

EAST COAST

MAP SHOWING ACREAGE HOLDINGS OF
HUDSON'S BAY OIL AND GAS COMPANY LIMITED
AT DECEMBER 31, 1974

The areas within which the Company has substantial holdings of petroleum and natural gas rights are indicated by the red color.

The Company has the exclusive right until December 31, 1999 to acquire leases on all petroleum and natural gas rights covering approximately 2.9 million acres of lands, most of which are distributed in a regular pattern — basically all or part of two one-square-mile sections in each 36-section township — in the areas covered by this pink color. These lands, formerly Hudson's Bay Company lands, are now beneficially owned by Siebens Oil & Gas Ltd.

developed foreign oil and gas rights at a total cost of $5.1 million.

During 1974 the Company participated in the drilling of four wells of which two were on the North Sea acreage and two were in Texas.

EXPLORATORY DISCOVERIES AND WELL COMPLETIONS — 1974

	Gross	Net
Gas Discoveries		
Netherlands, North Sea, Block K/4	1	.1
Texas, Panther Reef	1	.3
	2	.4
Dry	2	.1
Total Completions	4	.5

In the Netherlands North Sea, gas was discovered on block K/4 and a farmout well drilled by another company on block P/15 encountered encouraging shows of hydrocarbons before being abandoned as non-commercial. Additional wells will be drilled on both of these blocks to evaluate their potential. A well drilled by another company on acreage offsetting block F/5 was reported to be a substantial gas and condensate discovery and it appears that a minor portion of the reserves will extend to block F/5.

In the Texas Panther Reef area, a modest gas and condensate discovery was completed on a 2,600 acre block in which the Company has a 25% interest. Additional drilling is planned in this area in 1975.

In addition to the drilling activity, the Company participated in seismic programs on the North Sea acreage and in the Irish Sea.

MINERAL EXPLORATION

All of the Company's exploration for metallic minerals is conducted under a joint venture agreement with a wholly-owned subsidiary of Continental Oil Company. Each participant has a 50% interest in the joint exploration program which is operated by Hudbay Mining Company, a division of Hudson's Bay Oil and Gas.

In 1974 the Company's share of the costs of the joint exploration program was $635,000 compared with $770,000 in 1973. During the year exploration was carried out on six projects in the Cordilleras of British Columbia and the Yukon Territory, six projects in the Canadian Shield of Northern Ontario and Quebec, and on a project in the Gaspe area. Encouraging indications of mineralization have been found on several properties but a considerable amount of additional work will be required to determine their potential for development.

A substantial number of properties were released on completion of exploratory evaluation, particularly in British Columbia where onerous new royalty and tax legislation discourages mineral exploration. At year end the total holdings of the joint venture were 48,500 acres, of which 17,300 acres were in British Columbia; 9,400 acres in the Yukon Territory;, 9,700 acres in Ontario; and 12,100 acres in Quebec.

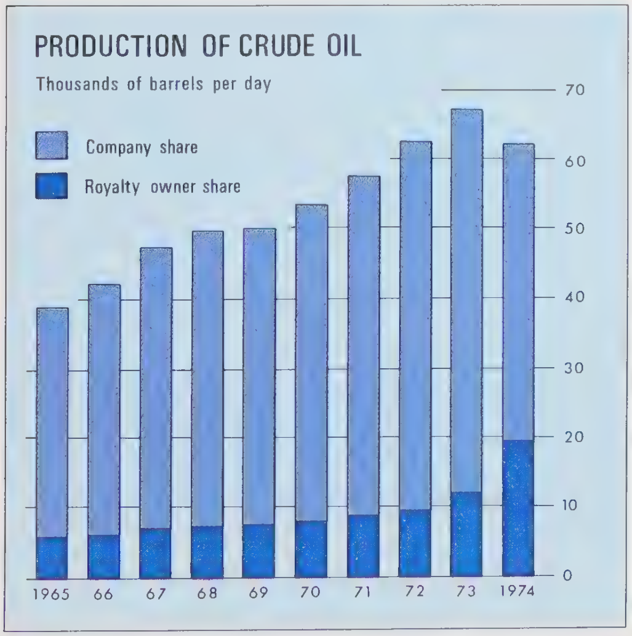
DEVELOPMENT DRILLING

Development drilling activity was significantly lower in 1974 primarily due to the completion of the shallow gas development program in the Medicine Hat area of Alberta and the unfavourable changes in royalties and income taxes which threatened the prospects for an economic return. The large development program initiated in 1973 in the shallow heavy oil area of Saskatchewan was suspended when it became apparent that higher royalties and income taxes would leave insufficient return to warrant continuation of the program. The number of net development wells completed by the Company in 1974 declined by 40% to 79.1 net wells. These completions included 21.4 net wells drilled under farmout agreements without cash outlay by the Company compared with 26.3 net wells in this category in 1973.

DEVELOPMENT WELL COMPLETIONS

	1974		1973	
	Gross	Net	Gross	Net
Oil	51	20.3	159	54.0
Gas	146	49.1	188	64.0
Dry	24	9.7	27	13.4
Total	221	79.1	374	131.4
Average Depth	3,356 feet		3,436 feet	

The 1974 development drilling program had an overall success rate of 88% and resulted in 63.7 successful net completions in Alberta, 5.6 in Saskatchewan and 0.1 in British Columbia. A total of 20.3 net oil wells were drilled, principally in the Alberta fields of Brazeau River, Caroline, Cessford, Claresholm and Twining. Most of the 49.1 net gas well completions were located in the Medicine Hat, Brazeau River, Edson and Pine Creek fields, also in Alberta.



CRUDE OIL

The Company's crude oil production before deducting royalties averaged 62,295 barrels per day in 1974, a decrease of 5,115 barrels per day or 7.6%. The more significant factors contributing to this reduction were the natural decline in productivity in the Zama, Pembina,

CRUDE OIL PRODUCTION

(Barrels Per Day)

Before Deducting Royalty

	1974	1973
Alberta		
Pembina	8,680	9,679
Virginia Hills	4,802	5,181
Kaybob South	4,771	4,415
Zama	4,045	5,978
Sturgeon Lake South	3,270	2,810
Bonnie Glen	2,797	2,597
Sundre	2,646	3,017
Innisfail	2,427	2,047
Medicine River	2,282	2,639
Fenn Big Valley and West	1,395	1,279
Nipisi	1,261	1,176
Swan Hills South	1,234	1,173
Sylvan Lake	1,164	1,329
Cessford	1,159	1,201
Redwater	1,006	1,303
Shekilie	726	1,184
Harmattan Elkton and East	667	670
Willesden Green	649	670
West Drumheller	600	749
Twining	528	566
Caroline	403	148
Bellshill Lake	335	1,076
Others	5,845	5,617
	52,692	56,504
Saskatchewan		
Lloydminster	1,188	829
Hummingbird	586	664
Success	572	762
Weyburn	323	404
Verlo	278	336
Battrum	256	381
Others	2,171	2,529
	5,374	5,905
British Columbia		
Milligan Creek	2,213	2,734
Peejay	989	839
Wildmint	618	926
Others	392	485
	4,212	4,984
Manitoba	17	17
Total	62,295	67,410
Total After Deducting Royalty	42,810	55,307

Milligan Creek and a number of other fields and the lower market demand resulting from reduced export shipments. In Alberta, further reductions occurred because of the full year impact of the November 1973 change in the method of establishing pool production rates and the December 1973 trade of Bellshill Lake producing properties for interests in the Athabasca oil sands. There were modest increases in production from new wells completed in 1973 and 1974, from plant expansions at Innisfail and Sturgeon Lake South, and from minor production improvements in a number of fields.

The average wellhead price received by the Company for its 1974 crude oil production was $5.54 per barrel, up $2.24 per barrel from the average for the prior year. The improvement reflects a $2.70 per barrel increase on April 1, 1974 and the full year effect of 1973 price increases.

NATURAL GAS LIQUIDS

Production of natural gas liquids (condensate and LPG) before deduction of royalties averaged 26,452 barrels per day, essentially the same volume as was produced in the prior year. Condensate production declined by 726 barrels per day or 3.6% due principally to changes in operating procedures in the Windfall field. LPG (propane and butane) production increased by 308 barrels per day or 4.7% with a large part of the gain attributable to normal output from the Harmattan plant where operations had been curtailed in 1973 due to an explosion and fire.

The average prices received for natural gas liquids are shown in the following comparative table:

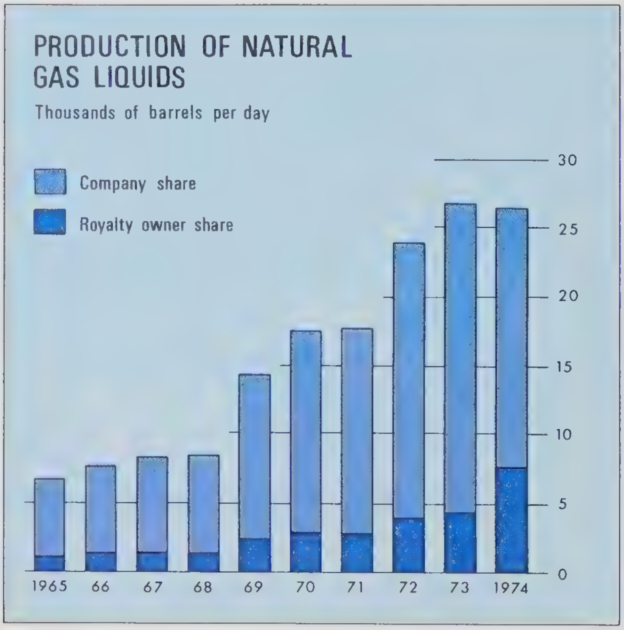
	Average Price Per Barrel 1974	1973	Increase
Condensate	$6.16	$3.76	$2.40
Propane	$4.89	$1.68	$3.21
Butane	$7.08	$2.24	$4.84

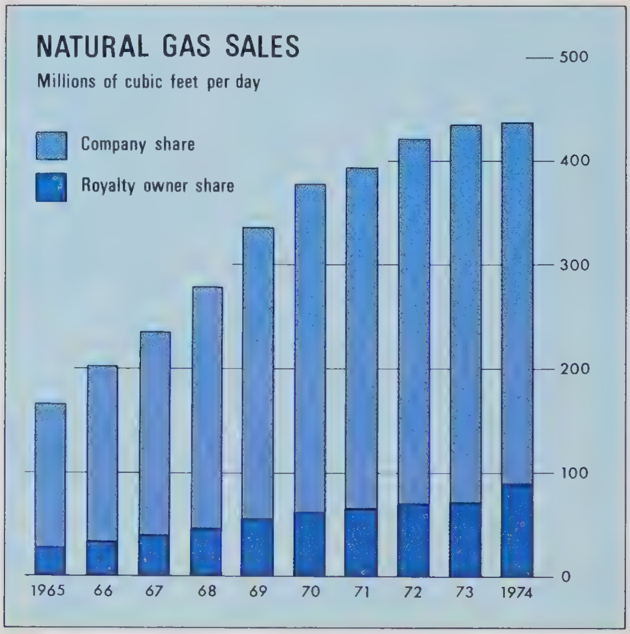
The price of condensate is closely related to the price of crude oil and the average for 1974 reflects a similar $2.70 per barrel increase on April 1. The improvement in propane and butane prices reflects the strong market demand for these commodities and a trend toward basing these prices on the cost of alternative fuels.

NATURAL GAS

Sales of natural gas before deducting royalties averaged 436.6 million cubic feet per day in 1974, an increase of 1.9 million cubic feet per day or 0.4%. The significant changes from the prior year were a substantial increase in deliveries from the expanded Brazeau River field and a reduction in the rate of production at Windfall which was necessary to improve the ultimate recovery of associated liquid reserves from that field.

Nearly 70% of the Company's natural gas sales are made to TransCanada Pipe Lines Limited





and approximately 17% to Alberta and Southern Gas Company Limited. All of the Company's TransCanada contracts were renegotiated in 1974 and the price for approximately 20% of current delivery volumes was increased from 26 cents to 60 cents per thousand cubic feet effective November 1, 1974. The price for these and all other contract volumes will be redetermined as of November 1, 1975. The Alberta and Southern contract prices were increased to an average of 51.4 cents per thousand cubic feet on July 1, 1974 and are scheduled for renegotiation on July 1, 1975. Sales to the British Columbia Petroleum Corporation account for approximately 7% of the Company's total deliveries at an average price of 19 cents per thousand cubic feet. This sales price is not directly comparable to that shown for other gas sales because no royalty is payable on gas sold to this government agency.

The average price realized by the Company for its 1974 gas sales was 24.8 cents per thousand cubic feet, compared with an average of 18.2 cents in 1973.

SULPHUR

Sulphur production before deducting royalty averaged 1,769 long tons per day, a decline of 9.0 percent which was principally a result of reduced raw gas deliveries to the Windfall Plant.

Sulphur sales before deducting royalty averaged 1,152 long tons per day, slightly lower than the 1973 volumes with reduced sales from the Windfall Plant nearly offset by larger volumes from other plants. Sulphur prices in both domestic and export markets improved substantially during 1974 and the average net price realized at the plant was $12.64 per long ton, an increase of $9.15 over 1973. The average price should show another good gain in 1975 as the current level of approximately $20 per long ton is expected to be maintained throughout the year.

GENERAL OPERATIONS

During the year continued emphasis was given to unitization projects which achieve economies by consolidating all of the development and production activities of various

NATURAL GAS AND ASSOCIATED PRODUCTS
Before Deducting Royalty

	NATURAL GAS SALES (Million Cubic Feet Per Day)		CONDENSATE PRODUCTION (Barrels Per Day)		LPG PRODUCTION (Barrels Per Day)		SULPHUR PRODUCTION (Long Tons Per Day)	
	1974	1973	1974	1973	1974	1973	1974	1973
Brazeau River	58.2	41.8	859	615	—	—	32	21
Caroline	20.5	18.1	552	517	510	468	8	7
Cessford Area	38.2	40.8	89	128	—	—	—	—
Clarke Lake	20.9	25.1	—	—	—	—	—	—
Edson	111.0	107.5	999	999	—	—	85	82
Gilby Area	6.3	6.7	66	67	—	—	—	—
Greencourt	7.8	6.2	79	68	—	—	—	—
Harmattan Area	5.8	7.9	519	557	351	236	5	6
Kaybob S No. 1	22.9	17.2	3,935	4,021	1,699	1,652	296	299
Kaybob S No. 2	4.0	3.0	2,774	2,773	986	905	211	215
Kaybob S No. 3	5.0	6.6	5,482	5,852	2,062	2,100	477	505
Lone Pine Creek	25.3	25.5	694	809	—	—	114	112
Medicine Hat Area	5.3	3.8	—	—	—	—	—	—
Pembina Area	4.3	5.5	87	98	290	329	—	—
Provost Area	4.4	4.3	17	22	—	—	—	—
Rimbey/Westerose	8.3	7.7	261	277	337	331	7	7
Sylvan Lake/Condor	11.9	11.8	185	198	351	374	1	1
Whitecourt (Windfall)	21.8	38.3	2,251	2,657	—	—	352	506
Others	54.7	56.9	707	624	310	193	181	182
Total	436.6	434.7	19,556	20,282	6,896	6,588	1,769	1,943
Total After Deducting Royalty	348.8	363.8	13,536	17,003	5,372	5,544	1,474	1,627

owners within a pool or area into a single operation. The Company has an interest in 231 units, including 10 that were established in 1974, and is the operator of 35 of them. Twelve new units are in the process of negotiation and it is expected that the Company will be the operator of two of them.

At year end the Company owned interests in 52 gas processing plants and was operator of 11 of them. Major compressor facilities, designed in 1974 for the Edson and Pine Creek gas fields, will be installed in 1975 to maintain production and increase recoveries of natural gas in these areas. In Pine Creek, large dehydrators are being relocated and line heaters installed to improve operating efficiencies and reduce atmospheric emissions. A project involving installation of additional facilities to improve sulphur recovery efficiencies at the Kaybob South complex is well underway with all major equipment having been ordered.

Engineering design and construction of the Zama Gas Plant is proceeding and it is anticipated that this facility will be placed on stream in the second quarter of 1976. The plant is designed to process 19.3 million cubic feet of sales gas per day of which the Company's share is expected to be 14 million cubic feet per day. The Company's share of natural gas liquids will be approximately 264 barrels per day.

Facilities are being installed in the Kaybob South Triassic oil field to extend the waterflood system and conserve gas produced in association with the oil. The Company's share of gas conserved will be approximately 1.0 million cubic feet per day and this additional volume will be processed at the Kaybob South Plant No. 1. Upon completion of the project in late 1975, the Company's crude oil production capacity will be increased by 900 barrels per day.

RESERVES

The Company's remaining recoverable hydrocarbon reserves at year end, as estimated by its reservoir engineering staff, are shown in the accompanying table. The reserves are reported before deducting royalties in accordance with the practice initiated this year.

The estimated proved reserves include only such reserves as can be reasonably classified as proved in accordance with widely accepted American Petroleum Institute standards. Probable reserves include reserves which are substantially proved on undrilled tracts closely associated with proved reserves and for which geological control is sufficient to offer good indication of continuity of the producing horizon. Incremental reserves from enhanced recovery techniques are included in the probable category when the required facilities are installed, and are transferred to the proved category only after the anticipated reservoir performance has been confirmed. Liquified petroleum gases are not included in the reported reserves of natural gas liquids unless the facilities required for their extraction are in existence or are assured of construction. The Company does not include in its reported proved and probable reserves its potential large volumes of heavy oil reserves in the Athabasca oil sands.

Additions and revisions to crude oil reserves amounted to 19.7 million barrels while production totalled 22.7 million barrels resulting in a net decline of 3.0 million barrels. Reserves of natural gas liquids declined by 10.7 million barrels as a result of production totalling 9.7 million barrels and modest declines due to revisions. Natural gas reserves declined by 106.0 billion cubic feet following production of 159.4 billion cubic feet.

RESERVES
Before Deducting Royalty

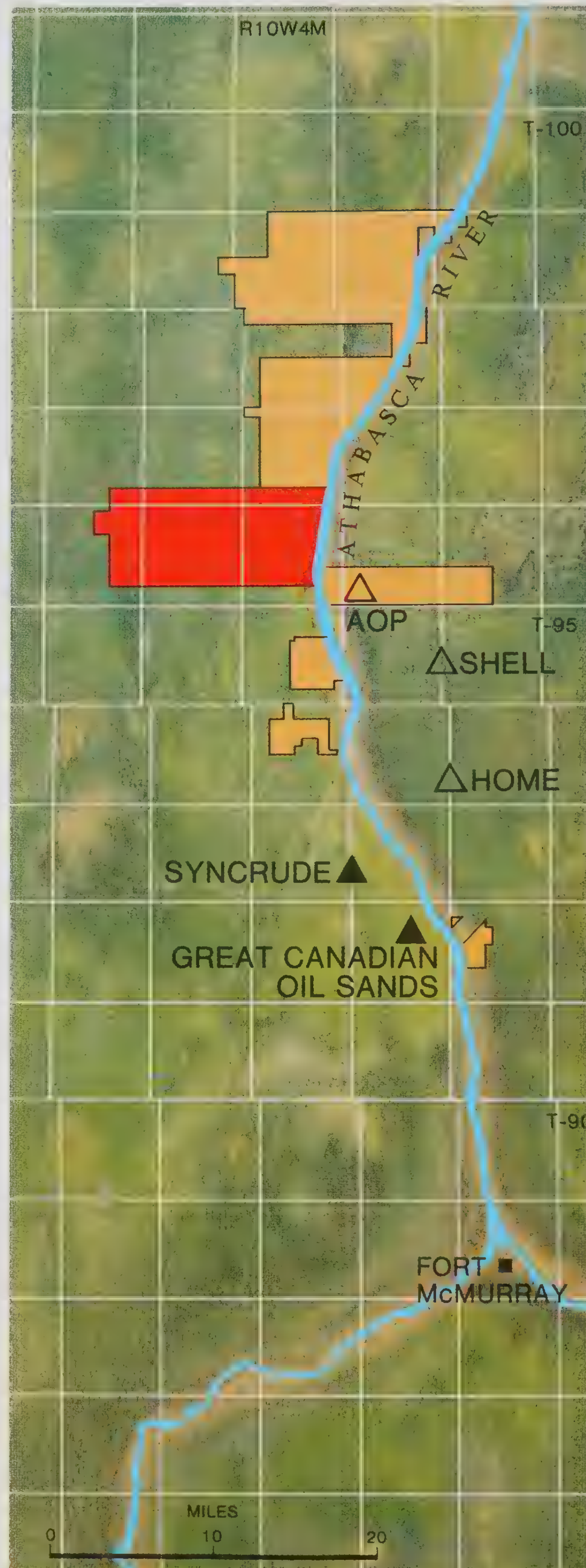
	Crude Oil (Barrels)	Natural Gas Liquid (Barrels)	Natural Gas (Millions of Cubic Feet)	Sulphur (Long Tons)
At December 31, 1974				
Proved	241,654,000	100,828,000	3,381,000	8,692,000
Probable	28,622,000	4,641,000	279,000	1,241,000
Total	270,276,000	105,469,000	3,660,000	9,933,000
At December 31, 1973				
Total	273,277,000	116,207,000	3,766,000	10,778,000

ATHABASCA OIL SANDS

The Company's principal representation in the Athabasca oil sands is through its participation in the Athabasca Oil Sands Project. Arrangements were made to increase its joint venture share in this project from 14.6% to 18.8% as of November 1, 1974 through the acquisition of a portion of the interest of one of the participants who is withdrawing from the group. The acquisition is subject to approval by the Foreign Investment Review Agency who are currently reviewing an application for such approval.

The Alberta Energy Resources Conservation Board has recently recommended to the Provincial Government that approval be granted to the AOP group with respect to its application to develop mining, extraction and upgrading facilities for the production of 122,500 barrels per day of synthetic crude oil. This production would be derived from a portion of the 103,400 acres of oil sands leases owned by the participants. The serious impact of inflation on construction costs and the uncertainty with respect to future oil prices and royalty and taxation rates have raised serious questions on the timing, ultimate cost and overall economic viability of the project. During 1974 the group carried out modest engineering and environmental studies and a core hole drilling program to define more accurately the limits of prospective mining areas. The level of activity in 1975 will be influenced by a complete reassessment of project economics and clarification of Government policies.

The Company also has a wholly-owned 50,000 acre lease in the Athabasca oil sands area. A core hole drilling program is being carried out on this property to determine the quality and extent of the deposits in prospective mining areas as well as in areas where the overburden is thicker and in-situ recovery methods would be required.



AOP LEASES

HBOG 100%

PLANTS IN OPERATION OR UNDER CONSTRUCTION ▲

PROPOSED PLANT SITES △

SUPPLY AND TRANSPORTATION

The volume of crude oil and natural gas liquids gathered and transported by the Rangeland Pipe Line Company division during 1974 averaged 111,969 barrels per day, a decrease of 2,555 barrels per day or 2.2% from the prior year. Movements into the U.S. Rocky Mountain area declined by 10,575 barrels per day or 10.1% from 1973 levels, due to the combined impact of federal government export controls and reduced demand resulting from the high export tax on crude oil and condensate. Field gathering system volumes declined modestly as a result of production restrictions in some of the pools served by the system and the lower level of industry exports to the U.S. The Federal Government's plan to phase out exports of crude oil and condensate indicate the probability of a continuing decline in volumes transported through the Rangeland trunk line system. The rate of decline is difficult to forecast, however, pending some indication of how the reduced volume of Canadian shipments will be allocated to the various U.S. market areas which are served by different pipe line systems.

Capital expenditures for miscellaneous improvements and connections to the Company's pipe line facilities amounted to $1.1 million in 1974 and the Company's net investment at year end amounted to $28.3 million. At year end the system comprised 450 miles of trunk line and 459 miles of gathering systems, all of which are located in Alberta.

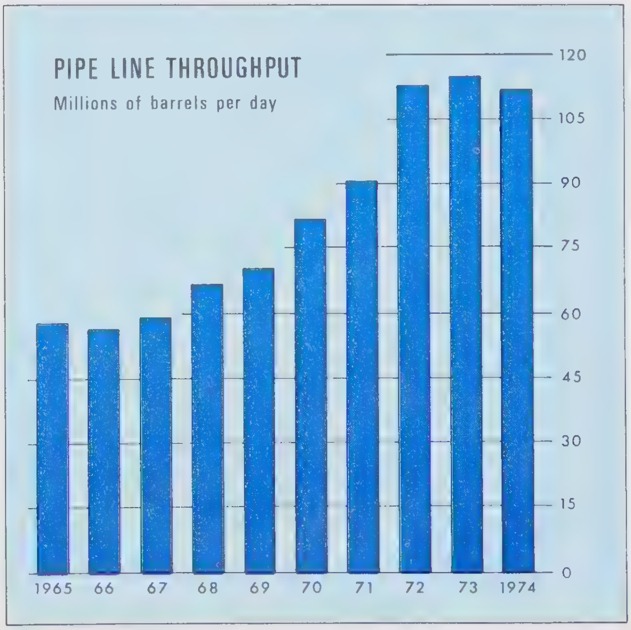
In addition to its own pipe line system, the Company continues to hold a 16-1/3% equity interest in Peace Pipe Line Ltd. (formerly Peace River Oil Pipe Line Co. Ltd.) which operates a gathering and trunk line system serving west central Alberta. Dividend income from this investment amounted to $413,000 in 1974.

OTHER OPERATIONS

Volumes handled through crude oil trading operations averaged 123,484 barrels per day in 1974, a decrease of 11.1% or 15,389 barrels per day. This decline reflects the lower level of exports to U.S. customers and reduced production at some of the fields and plants from which the Company purchases crude oil and condensate. Sales of LPG, at 8,097 barrels per day, were virtually unchanged from 1973.

BUSINESS DEVELOPMENT

Much greater emphasis is being placed on the search for business opportunities outside the traditional petroleum exploration and development activities to provide desirable diversification in revenue sources. A Business Development Department was formed during the year and its activities were primarily directed toward two business areas which appear to be appropriate for expansion of the Company's operations. The first involves investigation of the possibilities of engaging in further processing to upgrade the value of the Company's hydrocarbon production. A feasibility analysis is currently being carried out on a potential joint venture project which would use condensate as a feedstock for the production of a range of basic petrochemicals that are in strong demand. The other business area is the coal industry and the Department is evaluating the Company's modest holdings of coal rights in western Canada. Opportunities for the acquisition of additional coal properties with favourable prospects for near term development of economic mining operations are being investigated.



ENVIRONMENTAL CONSERVATION

During 1974 the Company continued its efforts to maintain increasingly stringent environmental standards. The Environmental Conservation Department increased the frequency of its program of regular inspections of all facets of field operations. Continuous monitoring of waste gases from natural gas processing plants was established to ensure that the sulphur content is maintained consistently below the stringent government requirements. In keeping with the Company's objective of reducing atmospheric emissions, a system utilizing newly developed technology to increase sulphur recovery from waste gases is being installed at the Kaybob South Gas Plant Complex at a cost of $4.7 million. In the Pine Creek gas field, a thorough environmental study resulted in the development of a modified producing system which will significantly reduce pollutant emissions.

A program for improvement of waste liquids control was continued. Waste liquids disposal at natural gas processing plants, field production facilities, and drilling operations takes place after appropriate treatment. Surface runoff from rain and snow in natural gas plant process areas now is confined, tested and treated to ensure safe disposal.

The Company has continued to train employees in the use of oil spill containment equipment, which is strategically located and can be quickly deployed in case of emergency. Contingency plans, which have been developed to enable the quickest action possible in the event of an oil spill, are regularly reviewed and updated.

Environmental research activities, carried out both separately and jointly with other companies, have increased during the past year. A continuing study of the effects of sulphur dioxide emissions on plant and animal life in the vicinity of natural gas processing plants has indicated no evidence of permanent or even significant damage. Environmental research activities of the Oil Sands Environmental Study Group, in which active membership is maintained, have been broadened and now include participation in a major provincial/federal government program. Substantial support has also been provided for a research program designed to determine the effects of drilling activities on sea life in the Beaufort Sea. In addition, the Company is carrying out a research program to determine the effects of oil ingestion by cattle, and is conducting specific reclamation studies on soil damaged by oil spills.

EMPLOYEES

During the year the Company was successful in meeting its increasing requirements for professional and technical staff through continuing education programs for employees and recruitment of new graduates from universities and technical schools. The development and upgrading of individual skills is encouraged through attendance at technical, professional and management courses and on-the-job training. A job progression program designed to upgrade the skills and qualifications of hourly-rated employees was implemented at the Kaybob Plant and will be extended to other plants in the future. As part of this program, employees are reimbursed for the costs involved in taking government apprenticeship courses and examinations to obtain a journeyman's qualification in their trade.

Through its Financial Aid to Education Program the Company made substantial contributions in support of higher education by providing funds for capital projects, grants, awards and scholarships. A graduate fellowship and 25 undergraduate scholarships, of which 20 were to sons and daughters of employees, were awarded at various Canadian universities.

The interest and support of employees and supervisors for the Company's accident prevention programs during the year was evidenced by ten awards received in recognition of safe plant operations and a decline in personal injuries and automobile accidents. A major program of noise pollution abatement was implemented at all operating facilities along with a hearing conservation program for all employees operating these facilities.

The Company has a comprehensive employee benefits program which includes vacation, holiday and sick pay benefits, health and life insurance programs and retirement benefits. It also includes a thrift plan designed to encourage employee savings through Company contributions related to the amount of employee deposits and length of service. A detailed review of this program was carried out in 1974 and a number of improvements were introduced effective January 1, 1975.

At year end the number of employees totalled 1,152, a net increase of 84 for the year. The Company also employed 90 university and technical institute students in temporary summer jobs. The total cost of salaries, wages and employee benefits amounted to $18.1 million in 1974, an increase of 22%.

Net earnings in 1974 were $58.4 million, a 48% improvement over 1973 earnings of $39.4 million. After providing for preferred dividends, net earnings amounted to $3.07 per common share compared to $2.07 per common share for 1973. Funds generated from operations advanced 23% to $91.5 million or $4.83 per common share.

Gross production revenues totalled $237.3 million, a gain of $89.6 million or 61%. The principal factors contributing to this gain have been discussed in the foregoing comments on operations.

Royalty deductions increased by 172% to a total of $68.5 million and were equivalent to 30% of gross production revenues for 1974 compared with 17.5% in the prior year. While Crown royalty rates vary widely by Province, product, and rate of production, the overall average for 1974 rose to 31% and will increase further in 1975 from the full year effect of the rate changes introduced in 1974. The average royalty rate paid on production from freehold mineral rights was 12% in 1974.

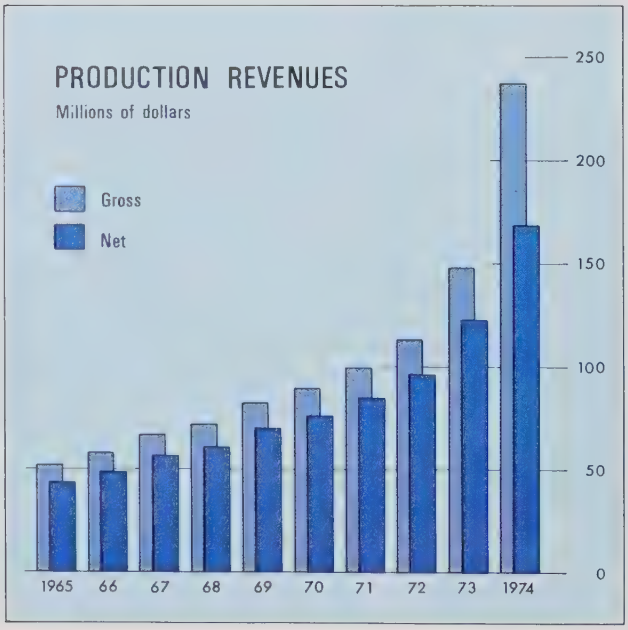
Net production revenues after deducting royalties totalled $168.8 million for the year, a gain of 38%, and the Company's other operating revenues from its pipe line and product trading operations increased by 3.2% to $14.4 million.

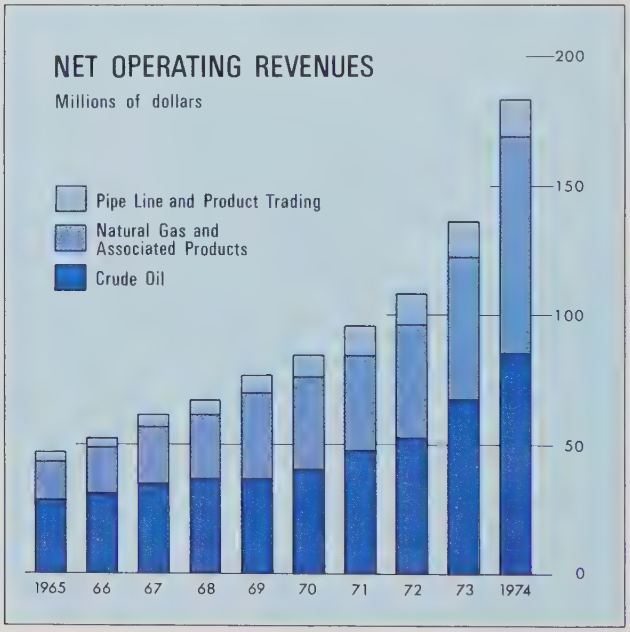
Income from investments and miscellaneous sources advanced to $6.9 million, a gain of $3.4 million arising from higher yields on larger holdings of short term investments and from insurance claims for revenues lost during insurable gas plant shut-downs.

Expenses, exclusive of income taxes, totalled $87.4 million, an increase of $9.7 million or

PRODUCTION REVENUES
Thousands of Dollars

	Gross Production Revenues			Royalties			Net Production Revenues		
	1974	1973	Percent Increase	1974	1973	Percent Increase	1974	1973	Percent Increase
Crude Oil	126,694	81,466	55.5	41,361	14,898	177.6	85,333	66,568	28.2
Natural Gas Liquids	58,926	32,539	81.1	17,612	5,437	223.9	41,314	27,102	52.4
Natural Gas	39,829	28,863	38.0	8,668	4,690	84.8	31,161	24,173	28.9
Sulphur	5,337	1,297	311.5	876	210	317.1	4,461	1,087	310.4
Processing Non-Owned Gas	6,516	3,516	85.3	—	—	—	6,516	3,516	85.3
Total	237,302	147,681	60.7	68,517	25,235	171.5	168,785	122,446	37.8





12.5%. Exploration expenses were up $2.4 million due to larger domestic geophysical and core hole drilling expenditures and the expanded foreign exploration program. Production expenses advanced by $5.4 million principally from inflationary escalation in the costs of materials and services. A $1.0 million increase in Administrative expenses relates primarily to higher wage and salary costs and expanded business development activities. Total charges for depreciation, depletion, and amortization were up by $1.9 million as a result of the continuing growth in assets. Dry hole and abandonment charges declined by $0.9 million largely due to the improved success ratio in the exploratory drilling program.

The provision required for current and deferred income taxes in 1974 totalled $44.4 million, an increase of $21.5 million or 94%. Changes in tax regulations and rates accounted for $7.9 million of the total increase and the remainder is attributable to higher taxable earnings. The more significant tax changes are detailed in Note 5 to the financial statements.

Dividends declared for the year totalled $18.2 million compared with $14.4 million in 1973. The semi-annual dividend on the common shares was increased by five cents to 45 cents per share in June and by a further five cents to fifty cents per share in December. This resulted in a total dividend of 95 cents per common share for 1974 compared with 75 cents per share in 1973. The Board of Directors proposes to initiate quarterly dividends on the common shares in 1975. Regular quarterly dividends totalling $2.50 per share were declared on the preferred shares in both 1974 and 1973.

Capital expenditures in 1974 totalled $45.7 million, up $2.7 million over 1973. A $7.3 million increase in outlays for exploratory drilling and acreage acquisitions together with an additional $6.3 million for gas processing plants and related facilities were partially offset by reductions of $6.7 million for development drilling and production facilities and $2.9 million for pipe line facilities.

Funds generated from operations together with proceeds from sales of properties and investments were more than adequate to cover capital expenditures, dividends, debt retirement and all other requirements for funds. As a result working capital increased by $21.4 million to $55.4 million. Outstanding long-term debt, including the portion due within one year, was reduced to $56.5 million or 19% of total debt and equity capital at year end.

There were a number of significant changes in working capital items during the year. Cash and short-term investments increased by $35.7 million to $78.4 million at December 31, 1974. Accounts receivable increased by $30.8 million and accounts payable were up $24.6 million, due principally to the large expansion in dollar volume of sales. Income and other taxes payable were $17.8 million higher than at the end of 1973.

At December 31, 1974, shareholders' equity totalled $240.8 million. On that date there were 18,922,079 common shares outstanding, of which Continental Oil Company held 53.1%, Hudson's Bay Company held 21.2% and the remaining 25.7% were held by 9,363 public shareholders. On a geographic basis 85% of the publicly-owned common shares were held in Canada, 11% in the United States, and 4% in other countries.

RESTATED QUARTERLY EARNINGS

The more significant income tax changes contained in the November 18 federal budget proposals were retroactive to May 7, 1974. In order to provide a proper comparison, quarterly earnings have been restated in the following table.

RESTATED QUARTERLY EARNINGS

	1974 As Previously Reported	1974 Income Tax Adjustments	1974 Adjusted Earnings	1973 Earnings	Year to Year % Change in Earnings
1st Quarter	$11,493,000	$ —	$11,493,000	$ 7,222,000	59.1%
2nd Quarter	16,964,000	(1,663,000)	15,301,000	9,573,000	59.8%
3rd Quarter	17,577,000	(2,870,000)	14,707,000	10,429,000	41.0%
4th Quarter		(3,326,000)	16,851,000	12,146,000	38.7%
Total Year		$(7,859,000)	$58,352,000	$39,370,000	48.2%

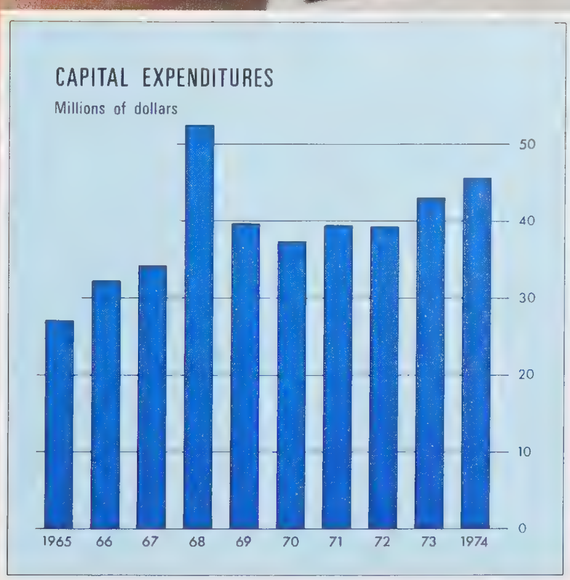
SUPPLEMENTARY FINANCIAL INFORMATION

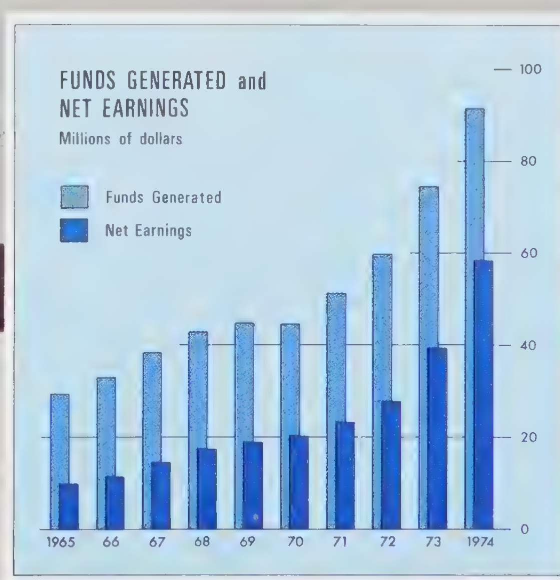
In December, 1974 the Canadian Institute of Chartered Accountants issued guidelines on "Accounting for the Effects of Changes in the Purchasing Power of Money". The basic principle of the procedures proposed by the C.I.C.A. is simply to restate all asset, liability, and transaction amounts in the financial statements in terms of dollars of the same period — which they have suggested should be the dollar of the end of the period covered by the statements. The objective of this "price level" adjustment procedure is to overcome the distortions created by conventional accounting procedures which are based on historical costs and therefore treat dollars of widely differing time periods as constant units of measurement when in fact they are substantially different in terms of current purchasing power. It is important to recognize, however, that this "price level" adjustment procedure does not purport to show assets or liabilities at their appraised value, replacement cost, or any other measure of their true current value — but merely restates the original dollar amounts (as used in the conventional accounting records) in terms of a constant measurement unit. The real current value of an asset or liability may be substantially different from the restated 1974 year end dollar amount of its original cost.

The C.I.C.A. suggested that its guidelines should be followed by corporations in publishing "price level" adjusted results as supplementary financial information with their 1974 Annual Reports to Shareholders. The Company's 1974 net earnings, restated in accordance with the C.I.C.A. guidelines, would be approximately 10% greater than the amount reported on the conventional accounting basis, but the rate of return provided by these restated earnings in relation to the restated amount of shareholders' equity would be approximately eight percentage points lower than the return shown by the conventional records.

The Company considers it inappropriate and potentially misleading to report its "price level" adjusted figures in detail because the procedures proposed by the C.I.C.A. are still tentative and may require significant revision before they are recognized as generally acceptable. The treatment proposed on a number of important items is highly contentious and conflicts with recommendations that have been made by other professional accounting bodies. For example, the C.I.C.A. guidelines propose that in restating earnings for the year a "price level" adjustment should be included on the total amount of deferred income taxes that has been accumulated on the balance sheet. Conversely, The American Institute of Certified Public Accountants recommends that no adjustment to earnings be made for the effect of "price level" changes on the accumulated amount of deferred income taxes. The very substantial differences that would result from the application of these divergent recommendations on this one item can be demonstrated by their impact in restating the Company's 1974 results. If no "price level" adjustment gain had been taken on deferred income taxes, our restated 1974 earnings would have been approximately 10% lower than conventionally reported earnings rather than 10% higher as indicated by the C.I.C.A. basis of restatement reported above.

The foregoing example is indicative of the major problems that are yet to be resolved in developing "price level" adjustment procedures. Nevertheless it is essential that acceptable inflation accounting procedures be developed as quickly as possible. These are necessary not only to improve the quality of reported earnings but, of even more importance, to provide a more rational and equitable basis for the calculation of income taxes. In a period of inflation the tax structure penalizes capital intensive industries, such as the oil and gas industry. In these cases taxable income is overstated by conventional accounting procedures because the revenues included in the calculation are essentially current dollars while the deductions from revenue for depreciation and similar charges are understated as they are based on historic dollar costs. Although the procedures proposed by the C.I.C.A. update the original dollar amount of these costs to an equivalent number of dollars of current purchasing power based on the changes that have occurred in general price levels, these restated original costs may be substantially different from current replacement costs due to a greater or lesser rate of change in the market prices for the specific items. When general price level adjustments do not fully offset the rate of escalation in replacement costs — and this is the current situation that prevails in replacing oil and gas reserves — it is essential that this be taken into consideration in calculating income taxes if the taxpayer is to retain sufficient capital to stay in business.


CAPITAL EXPENDITURES
Millions of dollars
0
10
20
30
40
50
1965
66
67
68
69
70
71
72
73
1974


FUNDS GENERATED and NET EARNINGS
Millions of dollars
Funds Generated
Net Earnings
0
20
40
60
80
100
1965
66
67
68
69
70
71
72
73
1974

CONSOLIDATED BALANCE SHEET
December 31, 1974 and 1973

ASSETS

	1974	1973
Current Assets		
Cash	$ 1,493,000	$ 1,845,000
Short term investments at cost, which approximates market	76,917,000	40,831,000
Accounts receivable (Note 2)	77,335,000	46,521,000
Inventories (Note 1)		
Products at lower of average cost or net realizable value	4,908,000	3,553,000
Materials and supplies at or below average cost	4,280,000	1,912,000
	164,933,000	94,662,000
Property, Plant and Equipment (Notes 1 and 3)		
At cost	520,725,000	485,220,000
Less: Accumulated depreciation, depletion and amortization	206,484,000	185,127,000
	314,241,000	300,093,000
Investments, Advances and Other Assets		
Investments and advances at cost	3,830,000	4,189,000
Unamortized bond discount and expense	467,000	521,000
Deposits, deferred charges and miscellaneous assets at cost	3,878,000	1,929,000
	8,175,000	6,639,000
	$487,349,000	$401,394,000

Approved on behalf of the Board:

Wayne E. Glenn Director

D. G. Jones Director

LIABILITIES AND SHAREHOLDERS' EQUITY

	1974	1973
Current Liabilities		
Accounts payable and accrued liabilities (Note 2)	$ 68,907,000	$ 44,259,000
Dividends payable (Note 2)	9,509,000	7,617,000
Income and other taxes payable	26,550,000	8,763,000
Long term debt due within one year (Note 4)	4,519,000	—
	109,485,000	60,639,000
Long Term Debt (Note 4)	52,003,000	57,983,000
Deferred Credits		
Advances received on future natural gas sales	4,992,000	5,535,000
Other	1,024,000	1,128,000
	6,016,000	6,663,000
Deferred Income Taxes (Note 5)	79,053,000	75,501,000
Shareholders' Equity		
Capital stock (Note 6)		
Authorized		
Preferred — $50.00 par value — 1,500,000 shares		
Common — $ 2.50 par value — 25,000,000 shares		
Issued and Outstanding		
5% Cumulative Redeemable Convertible Preferred Shares Series A — 76,590 shares (76,790 shares in 1973)	3,829,000	3,839,000
Common Shares — 18,922,079 (18,921,879 shares in 1973)	47,306,000	47,305,000
Contributed surplus (Note 6)	45,695,000	45,686,000
Retained earnings	143,962,000	103,778,000
	240,792,000	200,608,000
Contingent Liability (Note 8)		
	$487,349,000	$401,394,000

See Notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENT OF EARNINGS
Years Ended December 31, 1974 and 1973

		1974	1973
Revenues			
	Gross production revenues	$237,302,000	$147,681,000
	Less: Royalties	68,517,000	25,235,000
	Net production revenues	168,785,000	122,446,000
	Other operating revenues	14,415,000	13,971,000
	Investment and other income	6,895,000	3,457,000
		190,095,000	139,874,000
Expenses			
	Exploration	13,735,000	11,346,000
	Production	32,148,000	26,708,000
	Pipe line and product trading	2,843,000	2,750,000
	General administrative	4,216,000	3,187,000
	Depletion	7,682,000	7,398,000
	Depreciation	11,397,000	10,647,000
	Amortization of undeveloped oil and gas rights	5,053,000	4,194,000
	Dry holes and abandonments	5,945,000	6,881,000
	Interest (Note 4)	3,674,000	3,924,000
	Other	673,000	601,000
		87,366,000	77,636,000
Net Earnings Before Income Taxes		102,729,000	62,238,000
Income Taxes (Note 5)			
	Current	40,825,000	16,122,000
	Deferred	3,552,000	6,746,000
		44,377,000	22,868,000
Net Earnings (Note 1)		$ 58,352,000	$ 39,370,000
Net Earnings Per Common Share (Note 7)		$ 3.07	$ 2.07

CONSOLIDATED STATEMENT OF RETAINED EARNINGS
Years Ended December 31, 1974 and 1973

	1974	1973
Retained earnings — January 1	$103,778,000	$ 78,792,000
Net earnings	58,352,000	39,370,000
	162,130,000	118,162,000
Dividends declared		
Preferred shares	192,000	192,000
Common shares	17,976,000	14,192,000
	18,168,000	14,384,000
Retained earnings — December 31	$143,962,000	$103,778,000

See Notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION
Years Ended December 31, 1974 and 1973

	1974	1973
Sources of Funds		
Net earnings	$ 58,352,000	$ 39,370,000
Charges (credits) to earnings not involving funds:		
Depreciation, depletion and amortization	24,132,000	22,239,000
Dry holes and abandonments	5,945,000	6,881,000
Deferred income taxes	3,552,000	6,746,000
Other (net)	(479,000)	(613,000)
Funds generated from operations	91,502,000	74,623,000
Proceeds from sales of properties and investments	2,032,000	2,171,000
Total Sources of Funds	$ 93,534,000	$ 76,794,000
Uses of Funds		
Expenditures for property, plant and equipment	$ 45,685,000	$ 42,959,000
Reduction of long term debt	5,980,000	8,665,000
Dividends declared	18,168,000	14,384,000
Miscellaneous — net	2,276,000	197,000
Total Uses of Funds	$ 72,109,000	$ 66,205,000
Increase in Working Capital	$ 21,425,000	$ 10,589,000
Working Capital Changes		
Increase in Current Assets		
Cash and short term investments	$ 35,734,000	$ 15,806,000
Accounts receivable	30,814,000	16,371,000
Inventories	3,723,000	1,278,000
	70,271,000	33,455,000
Increase in Current Liabilities		
Accounts payable and accrued liabilities	24,648,000	14,537,000
Income and other taxes payable	17,787,000	6,436,000
Dividends payable	1,892,000	1,893,000
Long term debt due within one year	4,519,000	—
	48,846,000	22,866,000
Increase in Working Capital	$ 21,425,000	$ 10,589,000

See Notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Summary of Accounting Policies

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Hudson's Bay Oil and Gas Company Limited and its subsidiary companies, each of which is wholly-owned.

Accounts of foreign subsidiaries are stated in Canadian dollars. Current assets and liabilities are translated at year end rates of exchange. Property, plant and equipment and income accounts are translated at rates existing when acquired or incurred. Gains and losses (which are not material) upon revaluation and translation of foreign currencies are included in net earnings.

LEASEHOLD COSTS

Costs of oil and gas rights are capitalized when acquired. A regular charge is made to earnings for amortization (7.5% straight line per annum) of undeveloped oil and gas rights and when such rights are surrendered their cost is charged against the accumulated amortization. When undeveloped rights are proven to be productive the original cost is transferred to the developed oil and gas rights account and charged to earnings by an annual provision for depletion calculated on the unit of production method.

EXPLORATION AND DEVELOPMENT COSTS

Exploration expenses, including geological and geophysical costs, are charged against earnings as incurred. All costs of drilling wells are initially capitalized. If, on completion, a well is not capable of commercial production its cost is immediately written off. The costs of successful wells, other than equipment costs, are depleted on the unit of production method in the same manner as the cost of developed oil and gas rights.

DEPRECIATION

Plant, pipe line and equipment costs are depreciated on the straight line method at rates estimated to amortize the costs over the useful lives of the assets, except that certain pipe line assets are depreciated on the unit of throughput method.

The principal annual straight line rates in effect were as follows:

	1974	1973
Lease and well equipment	8%	8%
Plants and related facilities	5%	5%
Major trunk lines	4%	3%

RETIREMENTS

The general policy with respect to accounting for profit and loss on disposal of property, plant and equipment is to credit or charge such amounts to accumulated depreciation. An exception arises on the disposal of an entire property unit, in which event the profit or loss is credited or charged to income.

INVENTORIES

Inventories of crude oil, natural gas liquids and sulphur are valued at the lower of cost or net realizable value. Materials and supplies are valued at or below cost.

MAINTENANCE AND REPAIRS

Maintenance and repairs are charged to earnings. Renewals and replacements of a routine nature are also charged to earnings while those which improve or extend the life of existing properties are capitalized.

Note 2 — Amounts Owing To And From Affiliated Companies

Accounts receivable include $36,743,000 due from Continental Oil Company and its subsidiaries and accounts payable include $44,000 due to Continental Oil Company. The foregoing balances resulted from transactions in the normal course of business with most of the receivables relating to December sales of crude oil and natural gas liquids.

Dividends payable include $5,020,000 due to Continental Oil Company and $2,004,000 due to Hudson's Bay Company.

Note 3 — Property, Plant and Equipment

	December 31, 1974				
	Assets at Cost	Accumulated Depreciation	Accumulated Depletion	Accumulated Amortization	Net
Undeveloped oil and gas rights	$ 71,625,000	$ —	$ —	$19,035,000	$ 52,590,000
Developed oil and gas rights	35,291,000	—	17,290,000	—	18,001,000
Oil and gas rights on Siebens Oil & Gas Ltd. lands	1,000(1)	—	—	—	1,000
Wells and related facilities	239,353,000	42,949,000	79,775,000	—	116,629,000
Plants and related facilities	126,103,000	33,473,000	—	—	92,630,000
Pipe line and product trading facilities	40,444,000	11,664,000	—	—	28,780,000
Oil sands rights and predevelopment costs	1,825,000	—	—	—	1,825,000
Other	6,083,000	2,298,000	—	—	3,785,000
Total	$520,725,000	$90,384,000	$97,065,000	$19,035,000	$314,241,000

	December 31, 1973				
	Assets at Cost	Accumulated Depreciation	Accumulated Depletion	Accumulated Amortization	Net
Undeveloped oil and gas rights	$ 61,279,000	$ —	$ —	$15,874,000	$ 45,405,000
Developed oil and gas rights	34,563,000	—	16,014,000	—	18,549,000
Oil and gas rights on Siebens Oil & Gas Ltd. lands	1,000 (1)	—	—	—	1,000
Wells and related facilities	226,300,000	39,392,000	73,379,000	—	113,529,000
Plants and related facilities	116,438,000	28,091,000	—	—	88,347,000
Pipe line and product trading facilities	39,369,000	10,465,000	—	—	28,904,000
Oil sands rights and predevelopment costs	2,203,000	—	—	—	2,203,000
Other	5,067,000	1,912,000	—	—	3,155,000
Total	$485,220,000	$79,860,000	$89,393,000	$15,874,000	$300,093,000

(1) The Company has an exclusive right until December 31, 1999 to lease any or all of 2,609,000 acres of petroleum and natural gas rights owned in fee by Siebens Oil & Gas Ltd. A nominal value of $1,000 has been assigned to these rights.

Note 4 — Long Term Debt

	1974	1973
First Mortgage Sinking Fund Bonds		
4% Series A, due May 1, 1975 — remaining sinking fund requirements — $4,305,000 at maturity	$ 4,305,000	$ 4,928,000
5¾% Series C, due August 1, 1977 — remaining sinking fund requirements — $101,000 in 1975, $160,000 in 1976 and $100,000 at maturity	361,000	361,000
5½% Series D, due June 15, 1983 — remaining sinking fund requirements — $113,000 in 1975, $1,500,000 per annum 1976 to 1982 and $7,500,000 at maturity	18,113,000	18,718,000
7% Series E, due January 3, 1987 — remaining sinking fund requirements — Nil in 1975, $234,000 in 1976, $600,000 per annum 1977 to 1987	6,834,000	7,067,000
7.85% Series F, due April 15, 1994 (U.S. $25,000,000 issued and pledged to secure payment of the 7.85% Collateral Trust Bonds due 1994)	—	—
	29,613,000	31,074,000
Collateral Trust Bonds		
7.85% Collateral Trust Bonds due April 15, 1994 — sinking fund requirements U.S. $1,250,000 per annum 1979 to 1993 and U.S. $6,250,000 at maturity. (U.S. $25,000,000 recorded at the exchange rate in effect at date of issue. At the exchange rate prevailing on December 31, 1974, this liability would amount to $24,780,000)	26,909,000	26,909,000
	56,522,000	57,983,000
Less long term debt due within one year	4,519,000	—
	$52,003,000	$57,983,000

The aggregate payments of principal required on the foregoing long term debt in each of the next five years are as follows: $4,519,000 in 1975; $1,894,000 in 1976; $2,200,000 in 1977; $2,100,000 in 1978 and $3,350,-000 (including $1,250,000 U.S.) in 1979.

Interest expense of $3,674,000 includes interest of $3,640,000 on long term debt described in the above table and other interest charges of $34,000.

Note 5 — Income Taxes

In determining taxable income under the provisions of the Canadian Income Tax Act and Regulations for the period to May 7, 1974, the Company and each of its Canadian subsidiaries were permitted to deduct currently with respect to operations in Canada: exploration expenditures; acquisition costs of petroleum and natural gas rights; costs of drilling wells; and capital cost allowances which are greater than depreciation reported in the accounts. In accordance with the changes in legislation proposed in the November 18, 1974 Federal budget, deductions were restricted to 30% of the unclaimed amount of costs incurred after May 6, 1974 for the acquisition of petroleum and natural gas rights and for drilling successful wells except that the costs of drilling wells which resulted in the discovery of new pools of petroleum or natural gas and costs of wells which will not come into production in commercial quantities within twelve months of completion continued to be deductible currently. For operations conducted directly by the Company in foreign countries, exploration expenditures, the costs of drilling wells, and the acquisition costs of petroleum and natural gas rights were deductible in computing Canadian taxable income to the extent of 10% of the unclaimed costs.

In determining net earnings for corporate accounting purposes, the costs referred to above were charged against earnings on the basis as explained in Note 1. In the aggregate, costs claimed in the determination of income taxes payable have exceeded the related amounts charged in the determination of net earnings. An amount equivalent to the resultant reduction in current income taxes payable has been charged to earnings in the appropriate year and credited to Deferred Income Taxes to provide a proper matching of income tax expense with pre-tax earnings, which is the basic purpose of the tax allocation basis of accounting.

In determining the amount of taxable income for both tax and corporate accounting purposes, taxable profits realized prior to May 7, 1974 from the production of hydrocarbons in Canada were reduced by a depletion allowance of 33-1/3% and royalty income from hydrocarbon production during this period was reduced by a depletion allowance of 25%.

Effective May 7, 1974 income taxes were computed incorporating the changes in legislation proposed in the November 18, 1974 Federal budget and the tax credits proposed in the Alberta Petroleum Exploration Plan. Taxable production profits from the production of hydrocarbons in Canada were computed without any deduction for Crown royalties, rentals, taxes and other similar payments made to the Crown that are related to hydrocarbon production or the ownership of petroleum and natural gas rights. Taxable profits realized since May 7, 1974 were reduced by a depletion allowance of 25% which has been applied against the Company's accumulated "earned depletion". "Earned depletion" is being accumulated at the rate of $1.00 for each $3.00 of certain exploration and development expenditures incurred after November 7, 1969 and unclaimed amounts may be carried forward to qualify future claims for depletion allowances. During 1974 the Company accumulated $10 million of "earned depletion" and claimed $28 million of depletion allowances thereby reducing the unclaimed balance of "earned depletion" from approximately $35 million at December 31, 1973 to approximately $17 million at December 31, 1974. It is probable that the unclaimed balance of "earned depletion" at December 31, 1974 plus the amount expected to be accumulated in 1975 will be insufficient to allow the Company to claim maximum depletion on all of its production profits in 1975. The net result of the proposed federal and provincial tax changes is an increase in the 1974 income tax expense of $7,859,000 and a reduction in the net earnings per common share of $0.42.

No taxable income was generated in 1974 by any of the foreign incorporated subsidiaries of the Company and, in each case, all costs incurred will be carried forward as taxable losses which may be applied against future taxable income.

Note 6 — Capital Stock

The 5% Cumulative Redeemable Convertible Preferred Shares Series A are redeemable at the option of the Company before October 15, 1977 at $53.50 per share and thereafter at $51.00 per share. At the option of the holder each preferred share may be converted, subject to adjustment under certain circumstances, into one common share on or before October 15, 1977 or such earlier date as may result from notice of redemption of the shares. During 1974, 200 common shares were issued on conversion of 200 preferred shares. The excess

of the par value of the preferred shares converted over the par value of the common shares issued was $9,500 and this amount has been credited to Contributed Surplus. During 1973, 75 common shares were issued on conversion of 75 preferred shares.

At December 31, 1974 there were 76,590 common shares reserved for issue upon exercise of the rights of conversion attaching to the 76,590 preferred shares.

Note 7 — Net Earnings Per Common Share

Net earnings per common share are based on the monthly weighted average number of common shares outstanding and are after dividend requirements on the 5% Cumulative Redeemable Convertible Preferred Shares Series A.

Note 8 — Contingent Liability

The Company has guaranteed the payment of principal (amounting to $2,657,000 at December 31, 1974) and interest on certain outstanding debentures of a pipe line company in which it has a share ownership.

Note 9 — Remuneration of Directors and Officers

Aggregate direct remuneration paid or payable in 1974 by the Company and its subsidiaries to the Company's directors and officers amounted to $54,000 and $403,000 respectively. The equivalent amounts in 1973 were $60,000 and $367,000 respectively. During the year there were a total of 14 directors and 10 officers of whom two served in both capacities.

Note 10 — Retirement Plan

The Company has a contributory retirement plan which is open to all permanent employees. As confirmed by an independent actuarial evaluation at December 31, 1974, the assets of the retirement plan exceeded the liabilities for retirement benefits accrued to that date.

AUDITORS' REPORT

We have examined the consolidated balance sheet of Hudson's Bay Oil and Gas Company Limited and subsidiary companies as at December 31, 1974 and 1973 and the consolidated statements of earnings, retained earnings and changes in financial position for the years then ended. Our examination included a general review of the accounting procedures and such tests of accounting records and other supporting evidence as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company and subsidiary companies as at December 31, 1974 and 1973 and the results of their operations and the changes in their financial position for the years then ended, in accordance with generally accepted accounting principles applied on a consistent basis.

Peat, Marwick, Mitchell & Co.
Chartered Accountants

Calgary, Alberta
January 24, 1975

TEN YEAR FINANCIAL REVIEW (1)

	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965
Consolidated Statement of Earnings										
Net Production Revenues										
Crude Oil	$ 85,333	66,568	52,340	47,501	40,416	36,580	36,671	34,848	31,358	28,867
Natural Gas Liquids	$ 41,314	27,102	18,921	13,854	12,926	10,593	6,490	6,314	5,826	5,196
Natural Gas	$ 31,161	24,173	20,399	18,767	17,938	15,742	12,445	10,483	9,009	7,339
Sulphur	$ 4,461	1,087	992	1,446	1,421	4,272	4,004	3,641	1,527	1,428
Processing Non-Owned Gas	$ 6,516	3,516	3,261	2,783	3,061	2,659	1,381	1,389	1,197	820
Total Net Production Revenues	$168,785	122,446	95,913	84,351	75,762	69,846	60,991	56,675	48,917	43,650
Pipe Line and Product Trading Revenues	$ 14,415	13,971	12,720	10,956	8,428	6,649	5,893	5,013	3,565	3,567
Investment and Other Income	$ 6,895	3,457	2,197	2,665	4,154	4,867	3,887	1,667	782	577
	$190,095	139,874	110,830	97,972	88,344	81,362	70,771	63,355	53,264	47,794
Expenses										
Exploration	$ 13,735	11,346	9,689	8,972	8,321	9,438	8,339	7,436	6,176	5,628
Production	$ 32,148	26,708	21,336	18,880	15,629	13,416	11,062	10,134	8,501	7,752
Other Operating & Administrative,	$ 7,732	6,538	6,505	6,290	5,148	4,269	3,718	2,963	2,543	1,677
Depletion, Depreciation, Amortization & Dry Holes & Abandonments	$ 30,077	29,120	26,628	23,338	21,484	19,261	16,783	16,411	15,430	14,545
Interest	$ 3,674	3,924	4,128	4,539	5,478	5,588	4,059	4,272	3,243	2,837
	$ 87,366	77,636	68,286	62,019	56,060	51,972	43,961	41,216	35,893	32,439
Net Earnings Before Income Taxes	$102,729	62,238	42,544	35,953	32,284	29,390	26,810	22,139	17,371	15,355
Income Taxes — Current	$ 40,825	16,122	9,242	7,473	7,854	2,360	20	—	—	—
— Deferred	$ 3,552	6,746	5,553	5,325	4,260	8,147	9,389	7,623	6,055	5,527
Net Earnings	$ 58,352	39,370	27,749	23,155	20,170	18,883	17,401	14,516	11,316	9,828
Per Common Share	$ 3.07	2.07	1.44	1.18	1.02	.95	.87	.77	.62	.54
Funds Generated from Operations	$ 91,502	74,623	59,811	51,180	44,607	44,794	42,751	38,277	32,813	29,444
Per Common Share	$ 4.83	3.93	3.18	2.72	2.36	2.37	2.25	2.07	1.79	1.61
Financial Position										
Working Capital	$ 55,448	34,023	23,434	15,778	19,486	25,408	3,824	29,367	1,730	(3,456)
Property, Plant and Equipment — Net	$314,241	300,093	288,063	279,462	265,103	251,019	231,828	198,265	181,225	165,395
Long Term Debt	$ 52,003	57,983	66,648	68,417	75,334	83.061	62,593	69,743	66,653	55,300
Deferred Income Taxes	$ 79,053	75,501	68,755	63,429	58,104	53,844	45,697	36,308	28,685	22,630
Shareholders' Equity	$240,792	200,608	175,622	160,184	148,590	139,067	130,831	124,077	89,615	85,617
Capital Expenditures and Exploration Expenses										
Acquisition of Oil and Gas Rights — Domestic	$ 7,899	8,091	6,470	4,067	5,658	14,171	5,766	1,493	3,775	7,847
— Foreign	$ 5,067	—	—	—	—	—	—	—	—	—
Exploratory Drilling — Domestic	$ 8,641	6,789	8,117	5,182	5,286	4,031	5,303	8,053	5,873	4,535
— Foreign	$ 603	—	—	—	—	—	—	—	—	—
Total Exploration Capital Expenditures	$ 22,210	14,880	14,587	9,249	10,944	18,202	11,069	9,546	9,648	12,382
Development Drilling & Production Facilities	$ 10,219	16,931	12,875	10,436	8,821	10,893	10,622	13,100	8,891	7,618
Plants and Related Facilities	$ 10,976	4,718	9,554	15,524	15,462	8,663	26,428	6,049	4,788	5,861
Pipe Line and Product Trading Facilities	$ 1,079	3,985	1,589	2,802	1,680	1,496	3,305	5,085	8,536	847
Other	$ 1,201	2,445	732	1,348	457	425	932	536	354	362
Total Capital Expenditures	$ 45,685	42,959	39,337	39,359	37,364	39,679	52,356	34,316	32,217	27,070
Exploration Expenses										
Domestic Petroleum	$ 12,395	10,214	9,410	8,526	7,981	8,890	8,257	7,436	6,176	5,628
Foreign Petroleum	$ 705	362	—	—	—	—	—	—	—	—
Minerals	$ 635	770	279	446	340	548	82	—	—	—
Total Exploration Expenses	$ 13,735	11,346	9,689	8,972	8,321	9,438	8,339	7,436	6,176	5,628
Total Exploration Capital Expenditures & Expenses	$ 35,945	26,226	24,276	18,221	19,265	27,640	19,408	16,982	15,824	18,010
Total Capital Expenditures & Exploration Expenses	$ 59,420	54,305	49,026	48,331	45,685	49,117	60,695	41,752	38,393	32,698
Shareholders and Dividends										
Preferred Shares										
Number of Shares Outstanding (thousands)	77	77	77	600	600	600	600	600	—	—
Number of Shareholders	581	599	640	2,593	2,625	2,677	2,851	3,312	—	—
Market Price Per Share (2) — High	$ 51.00	63.00	60.00	62.00	62.50	60.00	63.50	62.75	—	—
— Low	$ 27.00	50.00	47.50	49.50	43.00	50.75	51.25	52.00	—	—
Dividends Declared Per Share — in equal quarterly amounts totalling	$ 2.50	2.50	2.50	2.50	2.50	2.50	2.50	0.625	—	—
Common Shares										
Number of Shares Outstanding (thousands)	18,922	18,922	18,922	18,294	18,294	18,294	18,294	18,294	18,294	18,294
Number of Shareholders	9,363	9,803	10,135	9,717	9,751	8,688	8,864	9,254	9,859	10,674
Market Price Per Share (2) — High	$ 47.75	57.50	57.50	49.50	51.00	45.00	46.00	46.75	25.50	19.50
— Low	$ 15.50	40.25	38.25	37.25	30.875	33.00	31.50	24.75	16.75	15.875
Dividends Declared Per Share										
First Half	$ 0.45	0.35	0.30	0.25	0.25	0.25	0.25	0.25	0.20	0.20
Second Half	$ 0.50	0.40	0.30	0.30	0.25	0.25	0.25	0.25	0.20	0.20
Total	$ .95	.75	.60	.55	.50	.50	.50	.50	.40	.40

TEN YEAR OPERATING REVIEW

	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965
Production Volumes										
Before Royalty (Barrels Per Day) (3)										
Crude Oil — Alberta	**52,692**	56,504	51,234	45,234	40,499	37,449	37,416	34,572	30,419	29,948
— British Columbia	**4,212**	4,984	5,618	6,806	7,557	7,176	6,718	6,698	6,173	3,627
— Saskatchewan	**5,374**	5,905	5,715	5,609	5,650	5,326	5,787	6,187	5,678	5,391
— Manitoba	**17**	17	19	20	21	22	22	19	16	15
	62,295	67,410	62,586	57,669	53,727	49,973	49,943	47,476	42,286	38,981
Condensate	**19,556**	20,282	19,123	14,207	14,189	12,017	7,277	7,505	7,102	6,336
LPG	**6,896**	6,588	4,886	3,606	3,243	2,258	1,161	786	680	541
Total Crude Oil & Natural Gas Liquids										
— Before Royalty	**88,747**	94,280	86,595	75,482	71,159	64,248	58,381	55,767	50,068	45,858
— After Royalty	**61,718**	77,854	73,279	63,809	60,168	54,426	49,515	47,294	42,456	38,890
Natural Gas Sales (Millions of Cubic Feet Per Day)										
— Before Royalty (3)	**436.6**	434.7	421.4	392.8	378.3	336.6	278.7	235.0	202.5	165.1
— After Royalty	**348.8**	363.8	352.3	328.8	317.0	281.7	233.3	196.7	169.5	138.2
Sulphur — (Long Tons Per Day)										
Production — Before Royalty (3)	**1,769**	1,943	1,930	1,485	1,482	1,126	590	567	476	406
— After Royalty	**1,474**	1,627	1,615	1,243	1,246	955	500	481	404	344
Sales — Before Royalty (3)	**1,152**	1,195	1,018	973	1,090	896	479	511	455	404
— After Royalty	**967**	1,000	852	814	917	760	406	433	386	343
Pipeline										
Throughput (Barrels Per Day)	**111,969**	114,524	112,799	90,463	81,930	70,135	66,578	58,812	56,123	57,502
Miles of Trunk Line	**450**	450	420	420	420	420	420	420	391	200
Miles of Gathering Facilities	**459**	456	431	450	450	425	423	366	334	314
Well Data										
Total Gross Wells Completed	**303**	501	381	199	225	244	166	203	222	195
Net Exploratory Wells Completed										
Oil	**5.6**	7.7	6.1	5.5	2.7	4.0	4.8	19.9	9.5	7.2
Gas	**16.9**	16.9	15.3	3.7	8.1	4.9	3.9	8.0	9.0	4.2
Dry	**17.6**	35.5	29.2	23.0	24.0	43.1	29.5	33.3	40.0	28.9
Total	**40.1**	60.1	50.6	32.2	34.8	52.0	38.2	61.2	58.5	40.3
Net Development Wells Completed										
Oil	**20.3**	54.0	72.6	21.8	23.8	31.5	19.3	30.0	34.8	38.4
Gas	**49.1**	64.0	44.7	10.6	13.4	19.8	16.2	17.1	9.8	10.3
Dry	**9.7**	13.4	14.2	9.5	12.3	6.7	6.9	8.8	12.1	11.0
Total	**79.1**	131.4	131.5	41.9	49.5	58.0	42.4	55.9	56.7	59.7
Net Wells Capable of Production										
Oil	**1,080.8**	1,069.9	1,056.4	1,013.3	1,010.7	1,010.3	978.7	992.2	957.1	919.7
Gas	**402.9**	357.7	289.2	256.9	241.9	226.5	201.1	189.7	166.8	152.7
Total	**1,483.7**	1,427.6	1,345.6	1,270.2	1,252.6	1,236.8	1,179.8	1,181.9	1,123.9	1,072.4
Oil and Gas Rights										
— Net (Thousands of Acres)										
Undeveloped										
British Columbia	**1,462**	1,411	1,624	1,459	2,634	2,391	1,078	980	1,025	1,203
Alberta	**4,698**	4,708	4,454	3,795	3,812	4,005	4,610	5,520	6,434	6,699
Saskatchewan	**3,249**	3,723	4,554	4,431	4,511	4,742	4,751	4,996	5,196	3,931
Manitoba	**128**	128	789	789	789	789	789	789	789	789
Northwest Territories (Including Arctic Islands & Baffin Offshore)	**7,576**	9,003	9,336	9,697	5,216	5,197	3,571	2,293	2,033	1,871
East Coast	**4,364**	5,095	6,048	7,942	5,195	5,195	5,405	4,583	9,167	9,167
Foreign	**139**	—	—	—	—	—	—	—	—	—
Total Undeveloped	**21,616**	24,068	26,805	28,113	22,157	22,319	20,204	19,161	24,644	23,660
Developed	**638**	596	570	544	534	512	472	405	383	356
Total	**22,254**	24,664	27,375	28,657	22,691	22,831	20,676	19,566	25,027	24,016
Proved and Probable Reserves										
Before Royalty (3)										
Crude Oil (Millions of Barrels)	**270.3**	273.3	310.1	330.4	332.4	335.1	337.3	343.5	277.4	251.9
Natural Gas Liquids (Millions of Barrels)	**105.5**	116.2	126.6	124.7	126.8	124.9	103.8	68.8	47.1	46.1
Natural Gas (Billions of Cubic Feet)	**3,660**	3,766	3,822	3,781	3,821	3,785	3,728	3,607	3,486	3,324
Sulphur (Thousands of Long Tons)	**9,933**	10,778	10,924	11,741	11,744	11,540	11,207	7,746	6,232	6,311
Employees										
Number of Employees	**1,152**	1,068	1,018	1,076	1,043	938	849	738	613	574
Salaries, Wages and Benefits	**$ 18,074**	14,778	13,066	12,375	10,763	9,096	7,549	6,130	5,249	4,268

(1) All dollar amounts are in thousands except for per share figures

(2) "Valuation Day Value" for Canadian income tax purposes — Preferred Shares $55.50; Common Shares $46.00

(3) Actual "before royalty" amounts are not available in the Company's records prior to 1973, therefore these amounts have been determined by using estimated average royalty rates in effect in each year.

Board of Directors

W. E. GLENN	Chairman, Houston, President of Western Hemisphere Petroleum Division and Director of Continental Oil Company
HERBERT H. LANK	Vice-Chairman, Montreal, Director of DuPont of Canada Limited
H. W. BLAUVELT	Stamford, Connecticut, Chairman of the Board of Directors and Chief Executive Officer of Continental Oil Company
G. H. BLUMENAUER	Hamilton, Chairman of the Board of Directors and President of Otis Elevator Company Limited
J. E. FINLEY	Houston, Executive Vice-President of Western Hemisphere Petroleum Division of Continental Oil Company
D. C. JONES	Calgary, President of the Company
A. M. McGAVIN	Vancouver, Chairman of the Board of McGavin ToastMaster Limited and Director of Hudson's Bay Company
D. S. McGIVERIN	Toronto, President and Director of Hudson's Bay Company
S. G. OLSON	Calgary, Executive Vice-President of the Company
GEORGE T. RICHARDSON	Winnipeg, President of James Richardson & Sons, Limited and Governor of Hudson's Bay Company
J. S. ROYDS	Stamford, Connecticut, Senior Vice-President, World-Wide Coordinator of Exploration and Director of Continental Oil Company
A. W. TARKINGTON	Lakeway, Texas, Director and Consultant, Continental Oil Company

Committees of the Board of Directors

EXECUTIVE COMMITTEE:

H. W. Blauvelt
W. E. Glenn
D. C. Jones (Chairman)
D. S. McGiverin
S. G. Olson

SALARY COMMITTEE:

H. W. Blauvelt
W. E. Glenn
D. C. Jones (Chairman)
D. S. McGiverin

RETIREMENT BOARD:

G. H. Blumenauer
K. H. Burgis
D. C. Jones
H. H. Lank (Chairman)
D. S. McGiverin

COMMITTEE ON AUDITS AND FINANCIAL CONTROLS:

G. H. Blumenauer
A. M. McGavin
A. W. Tarkington (Chairman)

Officers and Senior Management

D. C. JONES	President
S. G. OLSON	Executive Vice-President
K. H. BURGIS	Corporate Vice-President
J. DEMICHER	Financial Vice-President and Treasurer
R. J. HAMILTON	Vice-President, Exploration
W. D. STOREY	Vice-President, Production
L. B. BANNICKE	General Counsel and Assistant Secretary
P. T. BLACK	General Manager, Minerals Exploration
O. HUMENIUK	General Manager, Administrative Services
K. W. LLOYD	General Manager, Supply and Transportation
R. SEDGEWICK	General Manager, Production
W. E. SELBY	Corporate Secretary
A. R. TRAVERS	Controller
H. W. BECKER	Manager, Environmental Conservation
F. CALLAWAY	Manager, Special Projects
O. N. DEMCO	Manager, Employee Relations
G. REDLICH	Manager, Business Development
L. K. O'BERT	President, Hudbay Oil International Ltd.

Hudson's Bay Oil and Gas Company Limited
Incorporated in 1926 under the Laws of Canada

Head Office
320 Seventh Avenue South West, Calgary, Alberta T2P 0X5

Divisions
Hudbay Chemical Company
Hudbay Coal Company
Hudbay Mining Company
Rangeland Pipe Line Company

Subsidiary Companies (All Wholly-Owned)
Aurora Pipe Line Company, incorporated by Special Act of the Parliament of Canada
HBOG Mining Limited, incorporated under the Laws of the Province of Ontario
Hudbay Exploration, Inc., incorporated under the Laws of the State of Delaware
Hudbay Oil Company of Germany, Inc., incorporated under the Laws of the State of Delaware
Hudbay Oil (Ethiopia) Ltd., incorporated under the Laws of the Province of Alberta
Hudbay Oil International Ltd., incorporated under the Laws of the Province of Alberta
Hudbay Netherlands, Inc., incorporated under the Laws of the State of Delaware
Hudson's Bay Oil and Gas Company (U.K.) Limited, incorporated under the Laws of the United Kingdom
Rangeland Pipe Line Company Limited, incorporated under the Laws of the Province of Alberta

Transfer Agents
Common Shares
Montreal Trust Company,
Calgary, Montreal, Regina, Toronto, Vancouver and Winnipeg

Morgan Guaranty Trust Company of New York
New York

Preferred Shares
Montreal Trust Company,
Calgary, Montreal, Regina, Toronto, Vancouver and Winnipeg

Stock Exchange Listings (HBO)
Common Shares
Toronto Stock Exchange
Montreal Stock Exchange
American Stock Exchange

Preferred Shares
Toronto Stock Exchange
Montreal Stock Exchange

Auditors
Peat, Marwick, Mitchell & Co.
Calgary

ALCRAFT · CALGARY

Hudson's Bay Oil and Gas Company Limited Annual Report 1974

Hudson's Bay Oil and Gas Company Limited

320 Seventh Avenue South West
Calgary, Alberta T2P 0X5 Canada

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

Notice is hereby given that the Annual Meeting of the Shareholders of Hudson's Bay Oil and Gas Company Limited will be held at the offices of the Company, 320 Seventh Avenue South West, in the City of Calgary, in the Province of Alberta, Canada, on Tuesday the 22nd day of April, 1975, at the hour of 11:30 a.m. Mountain Standard Time, for the purpose of:

(1) receiving the Annual Report containing a Consolidated Balance Sheet as of December 31, 1974, Consolidated Statements of Earnings, Retained Earnings and Changes in Financial Position for the year then ended, and the Auditors' Report to Shareholders;

(2) electing directors;

(3) appointing independent auditors and authorizing the directors to fix their remuneration;

(4) considering and, if thought fit, sanctioning By-Law No. 23 enacted by the directors on the 7th day of December, 1974 authorizing the directors to divide the business and operations of the Company into such divisions and under such names as the directors may determine, (a copy of the said by-law is set forth in full in Exhibit "A" to the accompanying proxy statement and information circular); and

(5) transacting such other business as may properly be brought before the meeting and any adjournment thereof.

By Order of the Board.

W. E. SELBY
Secretary

Calgary, Alberta,
February 27, 1975.

Your vote is important. Should you be unable to attend the meeting in person, kindly sign the enclosed form of proxy and return it in the envelope provided at your earliest convenience.

Hudson's Bay Oil and Gas Company Limited

320 Seventh Avenue South West
Calgary, Alberta T2P 0X5 Canada

PROXY STATEMENT AND INFORMATION CIRCULAR

(Mailed to Shareholders on or about March 15, 1975)

SOLICITATION OF PROXIES

This proxy statement and information circular is furnished in connection with the solicitation by the management of Hudson's Bay Oil and Gas Company Limited (the Company) of proxies to be used at the Annual Meeting of Shareholders of the Company to be held at the time and place and for the purposes set forth in the accompanying notice of meeting. The solicitation will be by mail and the cost will be borne by the Company.

REVOCATION OF PROXIES

Pursuant to applicable Canadian law a shareholder who has given a proxy may revoke it, as to any motion on which a vote has not already been cast pursuant to the authority conferred by it, by an instrument in writing executed by the shareholder or by his attorney authorized in writing or, if the shareholder is a corporation, under its corporate seal or by an officer or attorney thereof duly authorized, and deposited either at the head office of the Company on or before the day preceding the day of the meeting or adjournment thereof at which the proxy is to be used, or with the Chairman of such meeting on the day of the meeting or adjournment thereof.

VOTING SHARES

As of the date of this proxy statement and information circular the Company had outstanding 18,922,079 common shares with a par value of $2.50 each, carrying the right to one vote per share. At that date 10,039,067 shares, being 53.06 per cent of the outstanding shares, were beneficially owned by Continental Oil Company, High Ridge Park, Stamford, Connecticut, U.S.A.; 1,925,322 shares, being 10.18 per cent of the outstanding shares, were beneficially owned by Hudson's Bay Company Investments Limited, 77 Main Street, Winnipeg, Manitoba, a wholly-owned subsidiary of Hudson's Bay Company; and 2,083,334 shares, being 11.01 per cent of the outstanding shares, were beneficially owned by Hudson's Bay Company, 77 Main Street, Winnipeg, Manitoba. The said 11.01 per cent interest will be voted by Hudson's Bay Company pending exchanges, if any, by holders of certain of its debentures for shares of the Company up to 1993 at an exchange price equivalent to $48 per share. Common shareholders of record at the time of the meeting will be entitled to attend and vote at the meeting or to be represented thereat by proxy. The Preferred Shares Series A of the Company do not entitle the holders thereof to vote at the meeting. A quorum for the meeting is at least two persons holding or representing an aggregate of more than one-half of the shares entitled to vote at such meeting.

Pursuant to an agreement dated September 24, 1970, Hudson's Bay Company and Continental Oil Company have agreed that so long as both companies together control the Company and the Company's option expiring in 1999 to explore for petroleum, natural gas and related hydrocarbons on Hudson's Bay Company lands (or any extension of such option) is in existence, both companies will exercise their voting rights at meetings of shareholders of the Company to ensure that at all times the proportion of the directors of the Company who are nominees of Hudson's Bay Company and Continental Oil Company, respectively, shall be not less than the proportion of outstanding common shares of the Company that are owned directly or indirectly by Hudson's Bay Company and Continental Oil Company, respectively. However, neither of the

parties to the said agreement has found it necessary to exercise its rights thereunder and the persons hereinafter named as nominees for election have been selected by unanimous decision of the Board of Directors of the Company. No rights have been waived by the parties with respect to future elections of directors.

In 1973 the Hudson's Bay Company lands to which the Company's aforementioned option relates and all rights relating thereto were assigned by Hudson's Bay Company to Siebens Oil & Gas Ltd., (Siebens), 300 Three Calgary Place, Calgary, Alberta, and in 1974 the Company entered into an agreement with Siebens replacing the former agreement between the Company and Hudson's Bay Company with respect to such lands. Under the agreement with Siebens the Company continues to have the option until 1999 to explore for petroleum, natural gas and related hydrocarbons on the lands subject to the former agreement with Hudson's Bay Company. During 1974 approximately $7.6 million was paid by or on behalf of the Company to Siebens on account of rentals, royalties and taxes with respect to such lands. In connection with the 1973 assignment to Siebens, Hudson's Bay Company acquired 35 per cent of the outstanding shares of Siebens and entered into agreements with the holders of 45 per cent of the outstanding shares of Siebens relating, among other things, to representation on the Siebens' Board and control over certain management actions of Siebens.

APPROVAL OF BY-LAW NO. 23

On December 7, 1974 the directors enacted By-Law No. 23, the text of which appears as Exhibit "A" to this proxy statement and information circular. The by-law authorizes the directors to divide the business and operations of the Company into such divisions and under such names as the directors may determine. The purpose of the by-law is to permit the use of divisional names which will provide for better public identification of activities carried on by the Company in addition to its petroleum exploration and production operations. In accordance with the by-law the directors have established divisions for conducting the following Company operations:

(1) Pipe line operations under the name "Rangeland Pipe Line Company, a Division of Hudson's Bay Oil and Gas Company Limited";

(2) Metallic mineral exploration and development operations under the name "Hudbay Mining Company, a Division of Hudson's Bay Oil and Gas Company Limited";

(3) Coal exploration and development operations under the name "Hudbay Coal Company, a Division of Hudson's Bay Oil and Gas Company Limited"; and

(4) Petrochemical operations under the name "Hudbay Chemical Company, a Division of Hudson's Bay Oil and Gas Company Limited".

By-Law No. 23 is required to be sanctioned by a majority of the votes cast at the meeting. In the event that the by-law is not so sanctioned at the meeting, it shall, at and from that time, cease to have force. Shares represented by properly executed proxies in favour of the persons designated in the enclosed form of proxy will be voted for the resolution sanctioning the by-law if not expressly directed to the contrary in such proxy.

ELECTION OF DIRECTORS

The Board consists of 12 directors to be elected annually. **Unless authority to vote is withheld, shares represented by properly executed proxies in favour of the persons designated in the enclosed form of proxy will be voted for the election of the nominees named below, all of whom are now members of the Board of Directors.** The management does not contemplate that any of the nominees will be unable to serve as a director but, if that should occur for any reason, the persons named in the enclosed form of proxy reserve the right to vote for another nominee in their discretion. Each director elected will hold office until the next Annual Meeting and until his successor is duly elected, unless his office is earlier vacated.

The following table sets out the name of each of the persons proposed to be nominated for election as a director; all other positions and offices with the Company now held by him, if any; his principal occupation; the year in which he became a director; and the approximate number of equity securities of the Company that he has advised are beneficially owned by him directly or indirectly, as of the date of this proxy statement and information circular.

Name	Other positions and offices with the Company now held	Principal Occupation	Director Since	Common Shares
Howard Woelfert Blauvelt[2]	Member of the Executive Committee	Chairman and Chief Executive Officer of Continental Oil Company	1971	Nil
George Henry Blumenauer	Member of the Committee on Audits & Financial Controls	Chairman of the Board of Directors and President of Otis Elevator Company Limited (manufacturer of elevators and escalators)	1971	100
James Edward Finley[2]	Nil	Executive Vice-President of Western Hemisphere Petroleum Division of Continental Oil Company since 1969	1974[3]	7
Wayne Edward Glenn[2]	Chairman of the Board and Member of the Executive Committee	President of Western Hemisphere Petroleum Division of Continental Oil Company	1962	31[4]
David Carlton Jones	President and Chairman of the Executive Committee	President of the Company	1966	2,540
Herbert Hayman Lank	Vice-Chairman of the Board	Director of DuPont of Canada Limited (manufacturer of chemicals, paints, commercial explosives, plastics and textile fibres)	1958	100
Allan Morton McGavin[1]	Member of the Committee on Audits & Financial Controls	Chairman of the Board of Directors of McGavin Toast-Master Limited (manufacturer of bread and bakery products)	1970	400
Donald Scott McGiverin[1]	Member of the Executive Committee	President of Hudson's Bay Company (a merchandising company)	1973	100
Stanley Granville Olson	Executive Vice-President and Member of the Executive Committee	Executive Vice-President of the Company	1971	16
George Taylor Richardson[1]	Nil	President of James Richardson & Sons, Limited (a financial, grain and management holding company) since prior to 1969	1974[3]	Nil
James Stanfield Royds[2]	Nil	Senior Vice-President of Continental Oil Company	1968	47
Andrew Wilson Tarkington[2]	Chairman of the Committee on Audits & Financial Controls	Director of Continental Oil Company	1964	Nil

1. Officer and/or director of Hudson's Bay Company.
2. Officer and/or director of Continental Oil Company.
3. Mr. Finley was appointed a director in June 1974 to fill the vacancy created by the death of Mr. John Godfrey McLean; and Mr. Richardson was elected a director in April 1974 in place of Mr. Thomas Norbert Beaupré, a nominee for re-election as a director at the 1974 annual meeting who died during the period between the mailing of the proxy statement to shareholders and the date of the meeting.
4. Does not include 40 shares owned by members of his immediate family in which he disclaims beneficial ownership.

As of the date of this proxy statement and information circular each of the following persons beneficially owns, directly or indirectly, the approximate number of equity securities of Continental Oil Company shown opposite his name:

Name	Common Stock
Howard Woelfert Blauvelt	5,446
James Edward Finley	1,788.8537
Wayne Edward Glenn	6,483
David Carlton Jones	100
Stanley Granville Olson	2,128
James Stanfield Royds	9,301
Andrew Wilson Tarkington	2,361

As of the date of this proxy statement and information circular each of the following persons beneficially owns, directly or indirectly, the approximate number of equity securities of Hudson's Bay Company shown opposite his name:

Name	Ordinary Shares
Allan Morton McGavin	2,000
Donald Scott McGiverin	20,000
George Taylor Richardson	18,950

REMUNERATION OF DIRECTORS AND OFFICERS

The following table sets forth the aggregate direct remuneration, retirement data and thrift plan data for the year 1974 for each director whose aggregate direct remuneration exceeded $40,000, and each of the three highest paid officers of the Company and for all directors as a group and all officers as a group.

Name of Individual or Identity of Group	Aggregate Direct Remuneration	Company Contributions under Thrift Plan[1]	Estimated Annual Benefits upon Retirement[2]
D. C. Jones . . . . President, Chairman of the Executive Committee and Director	$ 99,750	$ 4,250	$ 42,116
S. G. Olson . . . . Executive Vice-President, Member of the Executive Committee and Director	55,800	2,267	38,490
K. H. Burgis . . . . Corporate Vice-President	45,000	2,357	22,766
All directors as a group . . . . (14 persons)	53,933	—	—
All officers as a group . . . . (10 persons of whom 2 are directors)	403,256	17,600	224,033

1. Based on a participant's length of service and contributions to the Thrift Plan the Company contributes up to a maximum of 5% of the participant's current salary.

2. Based on the Retirement Plan benefit formula assuming each individual will continue in the employ of the Company at his present salary rate until retirement at age 65.

Under a Contingent Incentive Award Plan the directors may grant awards at annual intervals to selected senior management personnel. The total and individual amounts of awards to be granted will be determined each year by the directors based on the financial results achieved by the Company during the preceding fiscal

year and on the participants' individual contributions to such results, provided that the initial amount of an individual award may not exceed 25 per cent of the participant's annual salary at the date the award is made. Each award (together with annual increments thereto at rates ranging between 4 per cent and 11 per cent depending upon the Company's rate of return on shareholders equity) shall become payable, subject to the provisions of the Plan, upon termination of employment or in annual instalments (with interest on unpaid balances) over a period not exceeding 10 years following termination of employment. Cash payments made under the Plan in 1974 to all officers and directors as a group totalled $3,131 and at year end the amount set aside for future payments to all officers and directors as a group totalled $40,500, which included $17,500 for Mr. D. C. Jones, $9,000 for Mr. S. G. Olson, and $8,000 for Mr. K. H. Burgis.

APPOINTMENT OF INDEPENDENT AUDITORS

Unless authority to vote is withheld, shares represented by properly executed proxies in favour of persons designated in the enclosed form of proxy will be voted for the re-appointment of Peat, Marwick, Mitchell & Co., Calgary, as independent auditors of the Company until the next Annual Meeting of Shareholders and the authorization for the directors to fix remuneration.

The auditors propose to have a representative attend the meeting. Such representative will be given an opportunity to make a statement, if he so desires, and will be available to respond to any appropriate questions raised at the meeting.

OTHER MATTERS

The enclosed form of proxy confers discretionary authority upon the persons named therein with respect to amendments or variations to matters identified in the notice of meeting, and with respect to other matters which may properly come before the meeting. At the time of printing this proxy statement and information circular the management of the Company knows of no such amendments, variations or other matters to come before the meeting other than the matters referred to in the notice of meeting.

Dated: February 27, 1975.

EXHIBIT "A"

BY-LAW NO. 23

A By-Law to provide Divisions
of
Hudson's Bay Oil and Gas Company Limited

BE IT ENACTED as a By-Law of Hudson's Bay Oil and Gas Company Limited (hereinafter called "the Company") as follows:

1. The Directors may cause the business and operations of the Company to be divided into divisions based upon character or type of operations, geographical territories, manufactured products, method of distribution, type of product, or products manufactured or distributed or upon such other basis of division as the Directors may from time to time determine to be advisable and may cause the business and operations of any such division to be further divided into subdivisions or departments if deemed advisable by the Directors and upon such basis and under such names as the Directors may determine. The Company may transact business and execute contracts under its own corporate name, or, if authorized by the Directors, under one or more trade names approved for such purpose in such manner as may be authorized by the Directors; and, likewise, any division, subdivision or department into which any of the business or operations of the Company may have been divided may likewise transact business and execute contracts and other legal documents and sign cheques and do all other acts and things necessary or appropriate for and on behalf of the Company under one or more trade names if approved by the Directors and in such manner as may be authorized by the Directors.

2. The Directors may upon resolution designate and appoint officers assigned to a particular division, subdivision or department, into which any of the activities of the Company may be divided, with such official titles as the Directors may from time to time determine. Such appointed officers shall not be general officers of the Company except upon election to such additional corporate office. The appointed officers shall serve in such respective capacities at the will and desire of the Directors.

3. The duties, responsibilities and limitations of the officers of divisions, subdivisions or departments of the Company shall be such as the Directors may from time to time deem proper and the authority of such officers shall be limited to acts and transactions pertaining to the business which such division, subdivision or department is authorized to transact and perform, provided, however, that if the same individual is elected to a general office of the Company, the foregoing shall not limit his acts under the general powers and duties of such general corporate office.

ENACTED this 7th day of December, A.D. 1974.

WITNESS the corporate seal of the Company.

"D. C. JONES"
President

C/S

"W. E. SELBY"
Secretary